STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

NOI MANAGER'S REPORT

Docket 01 NOI-1

Notice of Inquiry into the Recent Increase in the Price of Natural Gas

Presented by
Thomas E. Kennedy

on behalf of the
NOI Staff

April 17, 2001

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

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I. Executive Summary

A. Background

On January 3, 2001, Governor George H. Ryan, in conjunction with the creation of the Energy Cabinet (see Executive Order #2, 2001), called upon the Illinois Commerce Commission ("ICC" or "Commission") to complete a full investigation of the recent natural gas price increases which have had a serious impact on Illinois consumers during the 2000/2001 winter heating season. As a part of its efforts to investigate natural gas prices and pursuant to the Commission's rules of practice, the Commission issued a Notice of Inquiry ("NOI"), designated as ICC Docket 01 NOI-1. An initial set of questions was issued by the Commission in the NOI on or about January 31, 2001, and a second set of questions was issued in a "Supplemental Notice of Inquiry" on or about February 7, 2001. In all, the Commission asked thirty questions spanning several different subject areas related to the causes and consequences of the high gas price. There were thirteen respondents to the NOI: 10 utilities and 3 non-utility organizations. This is the NOI Manager's Report, which provides the Commission with a set of findings and recommendations based on the investigation referenced above.

B. Organization of the Report

The main body of this report (Section IX: Review of the NOI Comments) provides a subject-by-subject review and analysis of the initial and reply comments submitted by the various respondents to the NOI on or about March 2 and March 12th, respectively, as well as the oral comments heard by the Commissioners in an open meeting on March 2. Within this subject-by-subject review of the respondents' comments, the Staff also relates supplemental information that may aid the Commission in its consideration of the issues raised by the NOI. One source of such supplemental information is the written transcripts from public meetings conducted by the Commission on January 18 and January 24. Finally, this section of the report discusses the recommendations of the respondents and reports the Staff's own findings and recommendations, within each of the following ten main subject areas:

A. Initial Questions on the cause of the high prices;
B. Efforts to Inform and Assist Customers;
C. Supply and Production;
D. Transmission;
E. Distribution;
F. Holding Companies and Affiliates;
G. Wholesale and Trading;
H. Projected Natural Gas Prices;
I. Hedging and Risk Management; and
J. Other Comments Not Directly in Response to NOI Questions

The Appendix to this report provides a relatively-detailed summary of each respondent's answer to each question in the NOI. The complete set of comments can also be found on the Commission's internet site, *www.icc.state.il.us*, more specifically at:

<http://www.icc.state.il.us/icc/gas/noi.asp>.

C. Acknowledgments

The NOI Manager wishes to thank all of the participants in the Commission's investigation for the time and effort that they expended in responding to the NOI questions, as well as the time and effort expended by various members of the Commission Staff who contributed greatly to the production of this report. Because this report was largely the product of multiple divisions, the finding and recommendations within this report are attributed to the "NOI Staff" rather than the NOI Manager.

D. Major Findings and Recommendations

In reviewing the record of this investigation, the NOI Staff concludes that the higher gas prices of the last twelve months have been due largely to factors that affected supply and demand. These factors will be enumerated in the main body of the report. No acts of market manipulation were reported to the Commission. Despite efforts by utilities and the Commission to provide advanced warning of the higher prices, customers were still unprepared for the magnitude of their winter heating bills. A significant contributor to the unwanted surprise was the record cold weather experienced in November and December, which pushed up wholesale (and retail) energy prices as well as the demand for space heating fuel.

Several recommendations were made during the course of the proceeding. Some parties recommended the initiation of rulemakings. As stated in 2 III. Adm. Code, Part 1700, it should be noted here that

> the Notice of Inquiry proceeding is not a rulemaking, but that information gathered may or may not form the basis for the initiation of rulemaking or for other purposes at a later date.

The NOI Staff is not recommending the initiation of any rulemakings, based on this NOI. However, further study and consideration of several issues is warranted, at this time. In particular:

- Utilities should continue to inform customers of anticipated gas price movements, conservation measures, and available budget and deferred payment plans. Also, utilities should continue to review and evaluate their communications and collection policies to determine what improvements can be implemented.
- The Commission should invite utilities and other potentially interested parties to participate in Staff-sponsored workshop discussions on the topic of energy usage estimation. Hopefully, such an effort will help to reduce the degree to which inaccurate energy use estimates lead to significant under- or over-collections from customers during periods of significant price volatility.
- Utilities should consider ways to limit ratepayers' exposure to gas price risk through prudent risk management practices.

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V. List of Speakers at the Commission's January 18 Gas Price Roundtable Meeting

Ms. Janice A. Dale
Chief of the Public Utilities Division
Illinois Attorney General's Office

Mr. Marty Cohen
Director
Citizens Utility Board

Ms. Marie D. Spicuzza
Supervisor for the Environment and Energy Department
Cook County State's Attorney's Office

The Honorable William Abolt
Commissioner of Environment
City of Chicago

Mr. Scott Glaeser
Manager of Natural Gas Supply and Transportation
Ameren

Ms. Susan Prebil
Energy Supply Representative
CILCO

Ms. Vonda Seckler
Energy Trading Representative
CILCO

Mr. Larry Altenbaumer
President
Illinois Power Company

Mr. Phil Cali
Executive Vice President of Operations
Nicor

Mr. Thomas M. Patrick
President and COO
Peoples Gas Light & Coke Company
and North Shore Gas Company

VI. List of Speakers at the Commission's January 24th Gas Price Roundtable Meeting

Mr. Robert Ladevich
Director of Planning and Energy
A. Finkl and Sons

Mr. Donato Eassey
First Vice President
Merrill Lynch

Mr. James Osten
Chief Energy Economist and Director of Fuel Analysis
Standard and Poors

Ms. Barbara Mariner Volpe
Senior Advisor, Oil and Gas Department
Energy Information Administration
U.S. Department of Energy

Mr. Skip Horvath
President
Natural Gas Supply Association

Ms. Cynthia Albert
Vice President
CMS Panhandle Pipeline Companies

Mr. Jim McElligott
Senior Vice President
Natural Gas Pipeline Company of America

VII. List of Organizations That Provided Written Responses to 01 NOI-1

UTILITY COMPANY RESPONDENTS:

Alliant Energy

Ameren

CILCO

Illinois Gas Company

Illinois Power

MidAmerican Energy Company

Mt. Carmel Public Utility Co

Nicor

Peoples Gas Light & Coke Co. / North Shore Gas Co.

United Cities Gas Company

OTHER RESPONDENTS:

Citizens Utility Board ("CUB")

Cook County State's Attorney's Office ("CCSAO")

Midwest Community Council ("MCC")

VIII. List of Speakers at the Commission's March 20th Public Meeting in 01 NOI-1

Mr. David Butts
Executive Vice President
Illinois Power

Mr. Rocco D'Alessandro
Vice President
Nicor Gas

Ms. Katherine A. Donofrio
Vice President
Peoples Gas Light & Coke Company
and North Shore Gas Company

Ms. Leijuana Doss
Assistant State's Attorney
Cook County State's Attorney's Office

Mr. D. Fondy James
Executive Director
Midwest Community Council

IX. Review of the NOI Comments

A. Initial Questions on the Cause of the Higher Prices

1. Discussion of Comments

The initial questions that were attached to the NOI primarily sought to determine the cause for the significant changes in natural gas prices, which escalated throughout 2000 and peaked in January 2001. With one exception,[1] the utilities verified that the price increases experienced by retail consumers over the last 12 months were entirely due to wholesale natural gas price increases that were passed through their purchased gas adjustment clauses ("PGAs").

All Illinois gas utilities currently recover their natural gas commodity costs and their interstate pipeline transportation and storage service costs through a PGA mechanism. This is a monthly price adjustment, which closely tracks the utilities' costs and is subject to an annual reconciliation, in which any residual over- or under-recovery of costs is accounted for and subsequently resolved through a rate adjustment applicable in the ensuing months. A comparison of PGA prices over the last three winters is

Table 1: PGA Rates over the Last Three Heating Seasons

	Simple Average of November through February PGA Rates		
	1998/1999	***1999/2000***	***2000/2001***
CILCO	27.94	32.20	77.25
AMEREN (CIPS)	32.07	36.94	67.70
Consumers Gas	33.55	32.13	84.89
Illinois Gas	35.27	41.39	92.51
IP - Rider A	28.08	31.23	70.23
Interstate - Area A	34.31	44.37	73.54
Interstate - Area B	23.02	20.16	68.86
MidAmerican Energy	32.19	39.35	78.44
Mt. Carmel	33.45	36.33	62.75
North Shore	27.68	34.52	81.18
NIGas	26.05	34.32	80.78
Peoples Gas	26.96	33.72	80.94
South Beloit	28.64	36.24	67.89
AMEREN (UE)	30.02	42.29	76.60
UC - Harrisburg	24.93	39.44	81.04
UC - Metropolis	27.52	40.10	76.73
UC - Salem	22.90	41.06	61.83
UC - Vandalia	22.47	38.38	78.75
UC - Virden	19.58	38.27	60.41
UC - St. Elmo	21.43	30.40	70.76

(Also see Figure 5, p. 7)

[1] The exception was MidAmerican, which was granted a base rate increase, based upon a 1998 test year, through a July 11, 2000 Order of the Commission. The Order authorized a monthly customer charge increase from $6 to $9 and an average distribution charge decrease from 9.6 cents per therm to 8.0 cents per therm. No year 2000-specific costs were included in that rate case. These increases are obviously small compared to the above.

shown in Table 1, while a comparison of the total commodity gas costs accounted for in the PGAs over the last two winters is shown in Table 2. The latter shows that state-wide total commodity gas costs increased 180% from $1.2 billion (during the September 1999 to April 2000 period) to $3.5 billion (during the September 2000 to April 2001 period), reflecting both an increase in commodity prices as well as an increase in usage.

Table 2: Comparison of Commodity Gas Costs Over the Previous Two Heating Seasons

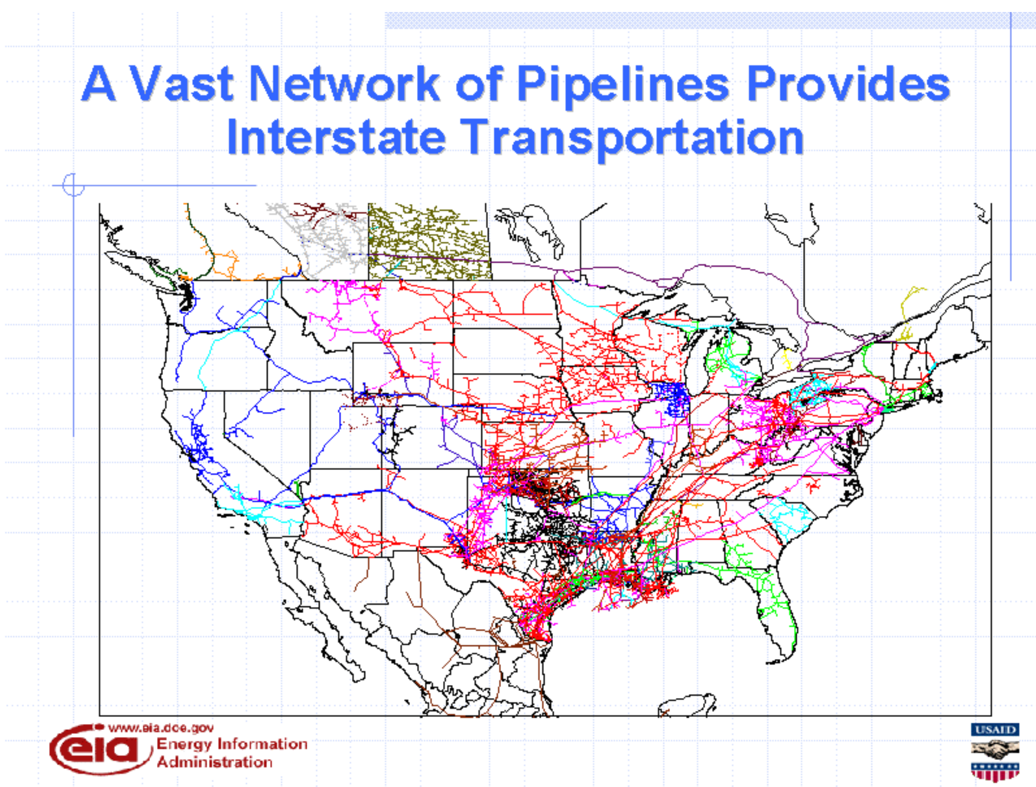
	Sept 00-Apr 01	Sept 99-Apr 00	Change	% Change
CILCO	$ 211,463,091	$ 71,210,543	$ 140,252,548	197%
CIPS	$ 120,148,788	$ 43,408,530	$ 76,740,258	177%
Consumers Gas	$ 5,587,217	$ 2,234,564	$ 3,352,653	150%
Illinois Gas	$ 9,722,663	$ 3,616,115	$ 6,106,548	169%
Illinois Power	$ 351,153,819	$ 126,307,523	$ 224,846,296	178%
Interstate Power	$ 4,637,991	$ 1,834,816	$ 2,803,175	153%
MidAmerican Energy	$ 60,874,979	$ 20,873,860	$ 40,001,119	192%
Mt. Carmel	$ 2,684,695	$ 1,080,633	$ 1,604,062	148%
NiGas	$ 1,669,988,208	$ 618,325,907	$ 1,051,662,301	170%
North Shore	$ 170,253,728	$ 55,661,458	$ 114,592,270	206%
Peoples	$ 862,033,799	$ 292,693,632	$ 569,340,167	195%
South Beloit	$ 6,338,000	$ 3,075,100	$ 3,262,900	106%
Union Electric	$ 13,587,389	$ 4,698,521	$ 8,888,868	189%
United Cities	$ 19,633,768	$ 7,319,876	$ 12,313,892	168%
Total	**$ 3,508,108,135**	**$ 1,252,341,078**	**$ 2,255,767,057**	**180%**

While some utilities noted that they incurred unusual costs for mercury investigation, inspection, and clean-up during 2000, these costs were recovered neither through the PGA nor through any other adjustment in retail rates. Similarly, many utilities cited some increased costs in 2000 for their own use of natural gas, for their efforts to respond to consumer questions and complaints, for customer service, for public relations, for mass communication, for carrying costs, as well as for higher unpaid debt expenses. None of these additional costs were recovered through the PGA. All such costs are normally recovered through base rates, which do not fluctuate by month like the PGA. Typically, such base rates are altered after the Commission has conducted a thorough "rate case" which can take up to 11 months to complete.

To place the recent price increases into context, the history of natural gas prices is displayed in a series of graphs on the next several pages. Figure 1 shows the vast interstate pipeline system which moves gas throughout North America (the most dense cobwebs of lines revealing the major producing regions and market hubs. Figure 2 shows the annual average of U.S. wellhead prices, from 1970 through 1998. Chronologically, Figure 3 picks up where Figure 2 leaves off, but switches to showing the **monthly** averages of U.S. wellhead prices, through January 2001. Figure 3 also shows the level of prices for the New York Mercantile Exchange's Henry Hub natural gas futures contract. Henry Hub is a major trading point for gas flowing from producing regions of Texas, Louisiana, and Oklahoma to consuming regions in the Midwest and the East. Finally, Figure 4 shows the monthly PGA prices, since January 1998, of five of the largest gas utilities in Illinois.

Examination of the graphs, cited above, shows the significant increases in gas prices that have occurred at both the wholesale and retail levels over the last 12 months. On the wholesale side, for instance, last-trade date settlement prices of the NYMEX gas futures peaked for the

Figure 1: Interstate Pipeline System



Source: Barbara Mariner-Volpe, "The Evolution of Gas Markets in the United States" Energy Information Administration, Slide-show presentation, May 2000.
<http://www.eia.doe.gov/pub/oil_gas/natural_gas/presentations/2000/evolution_gas/index.htm>

Figure 2: Natural Gas Wellhead Prices

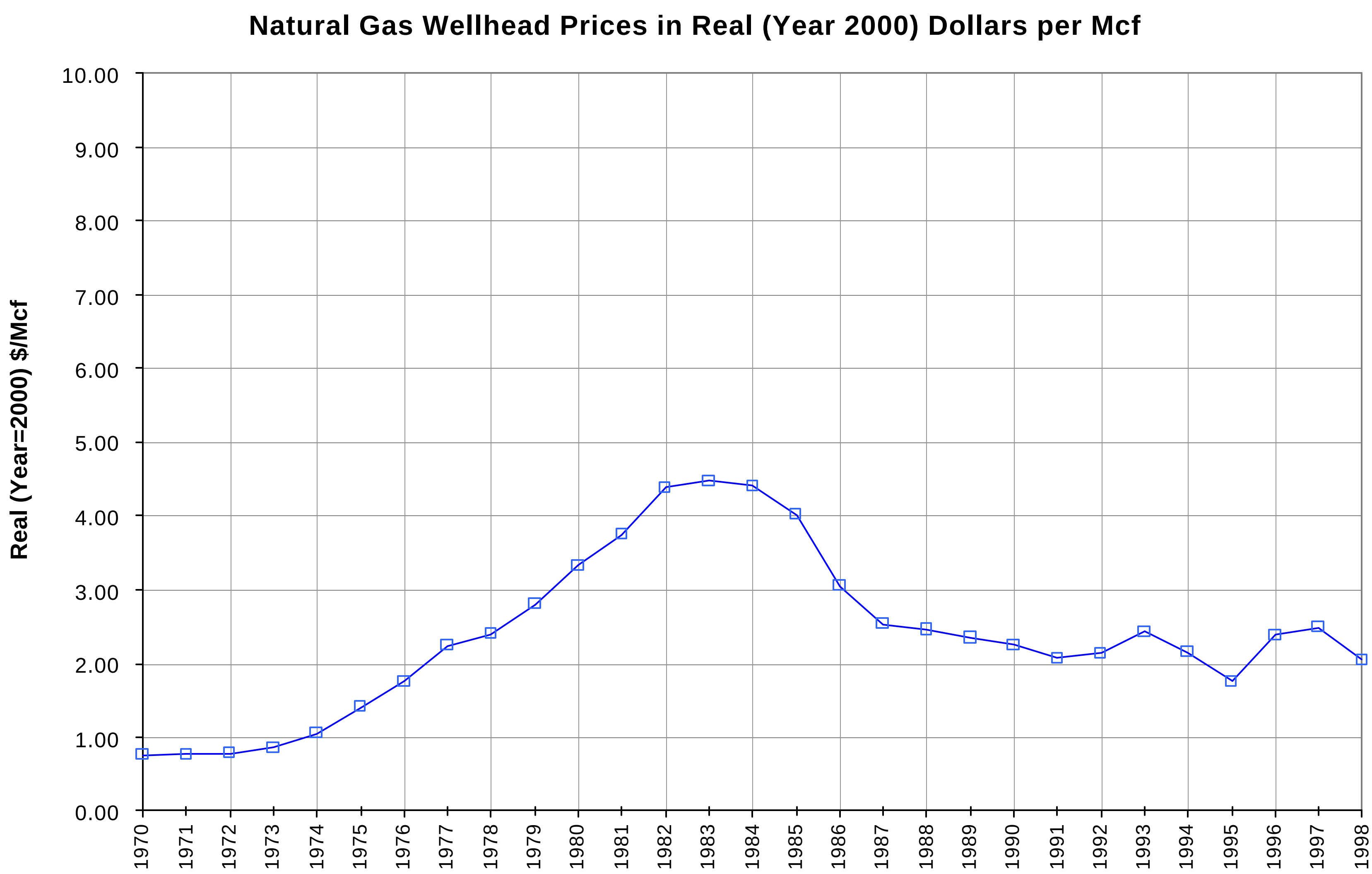


Figure 3: Wholesale Gas Prices Since January 1998

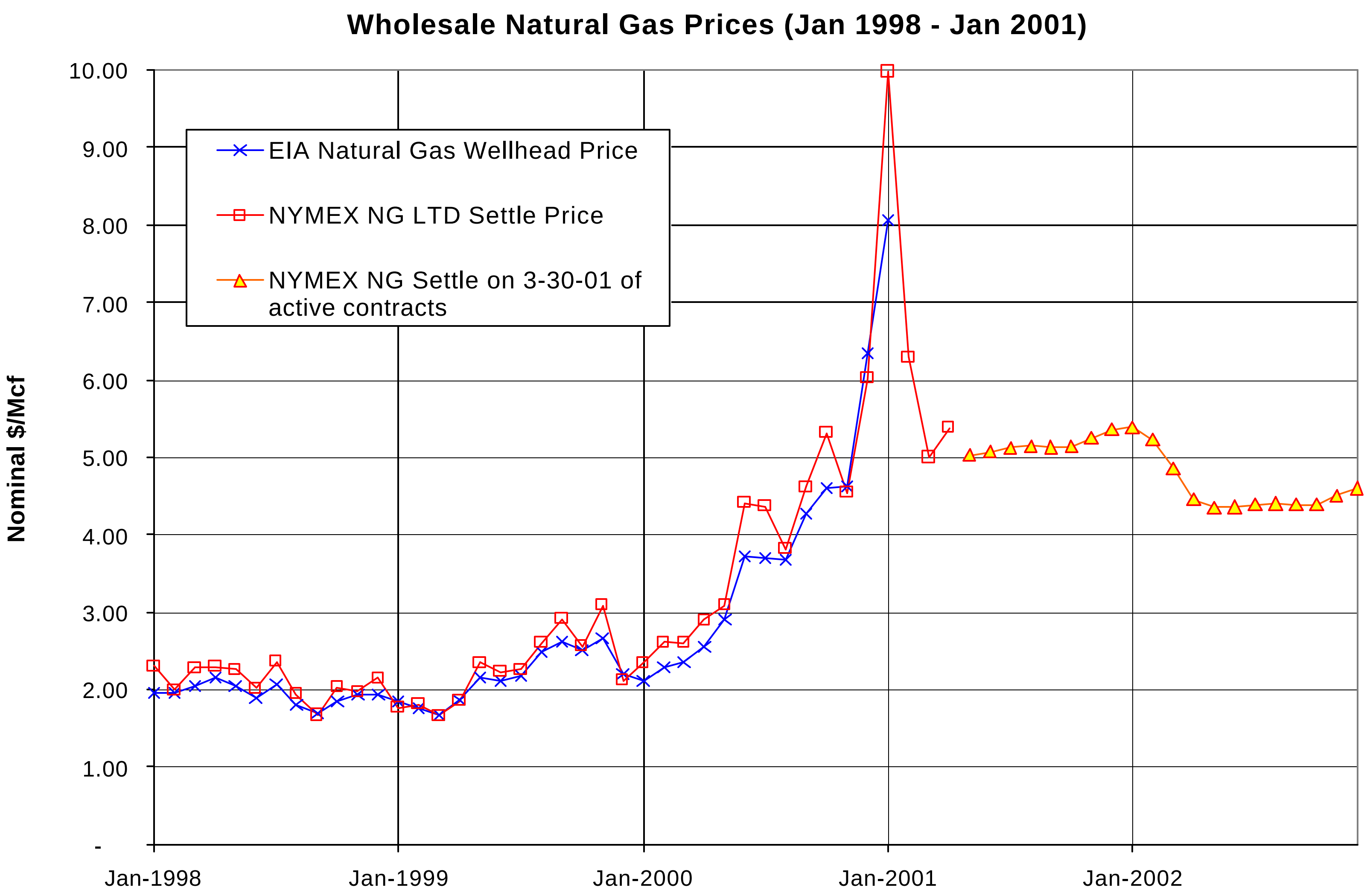


Figure 4: Monthly PGA Rates Since January 1998

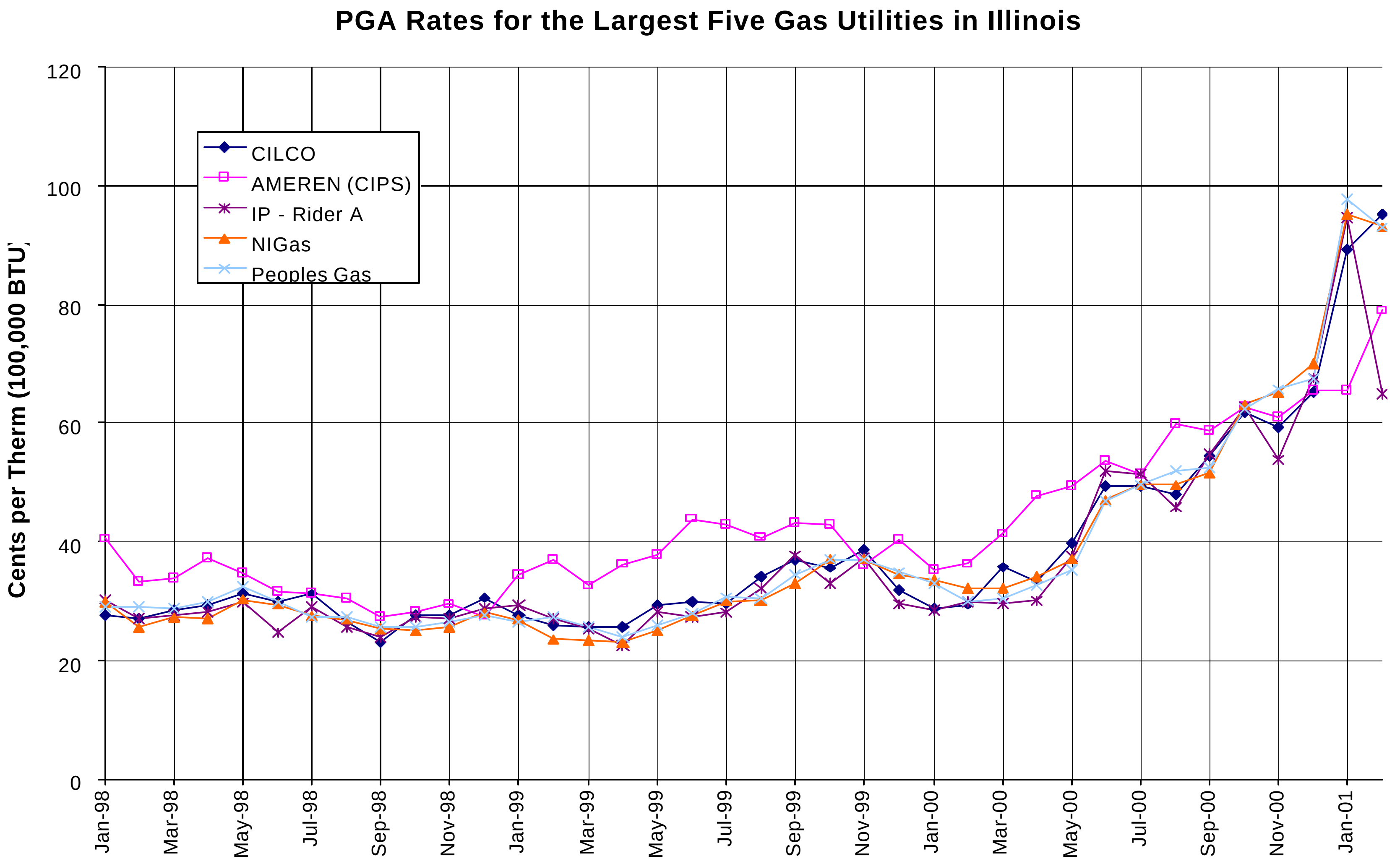


Figure 5: Comparison of Last Three Winter's PGA Rates

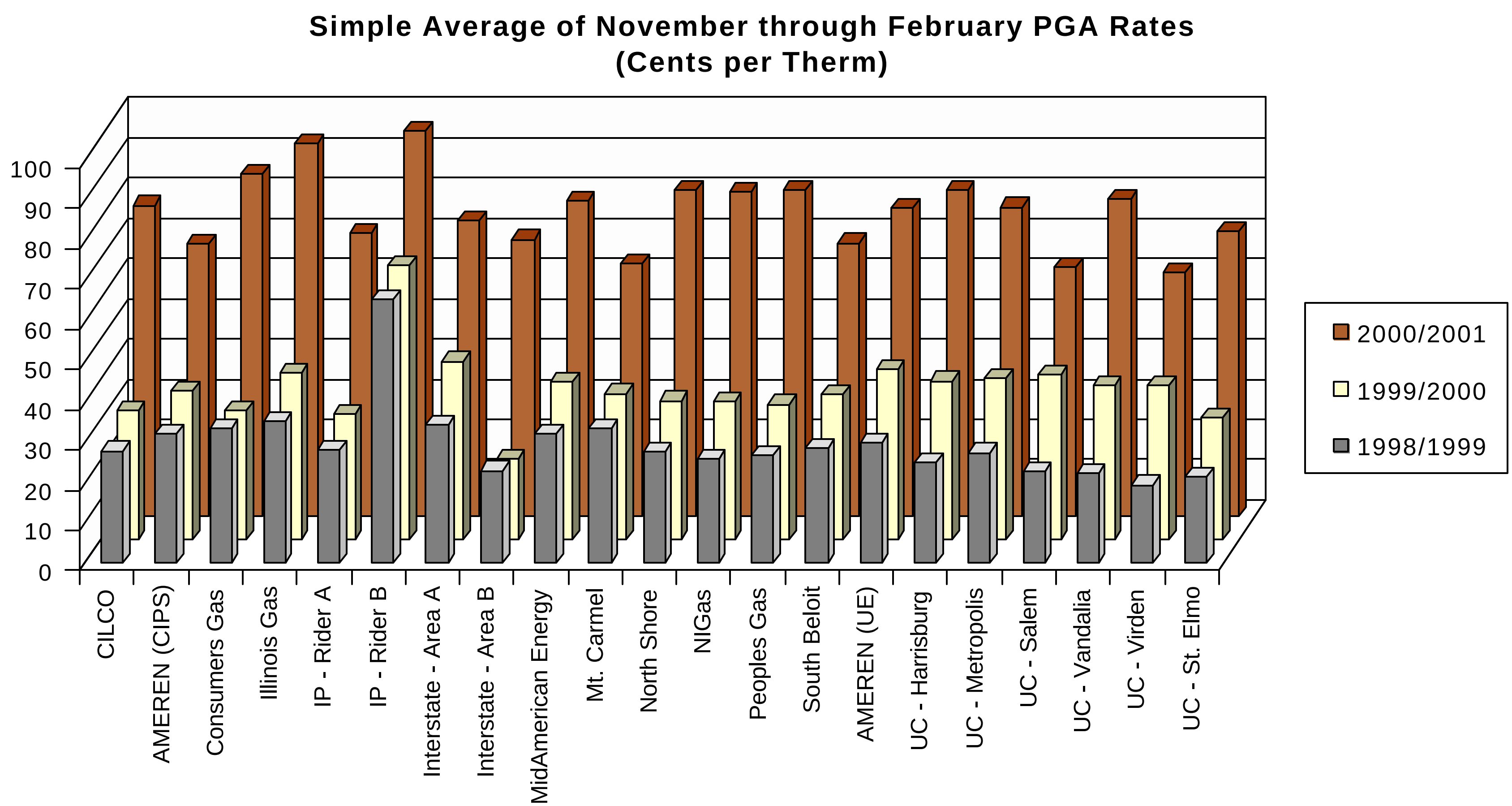
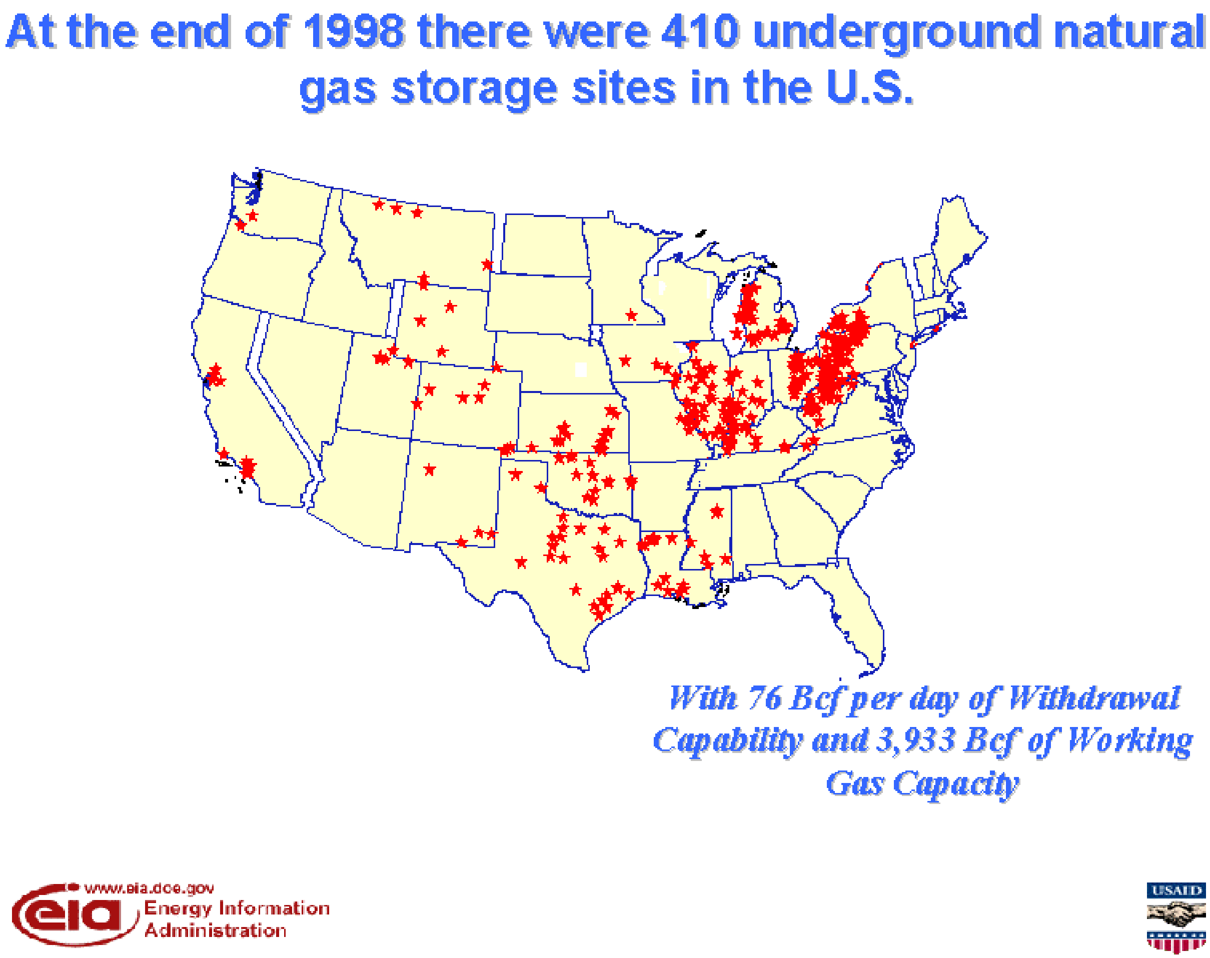
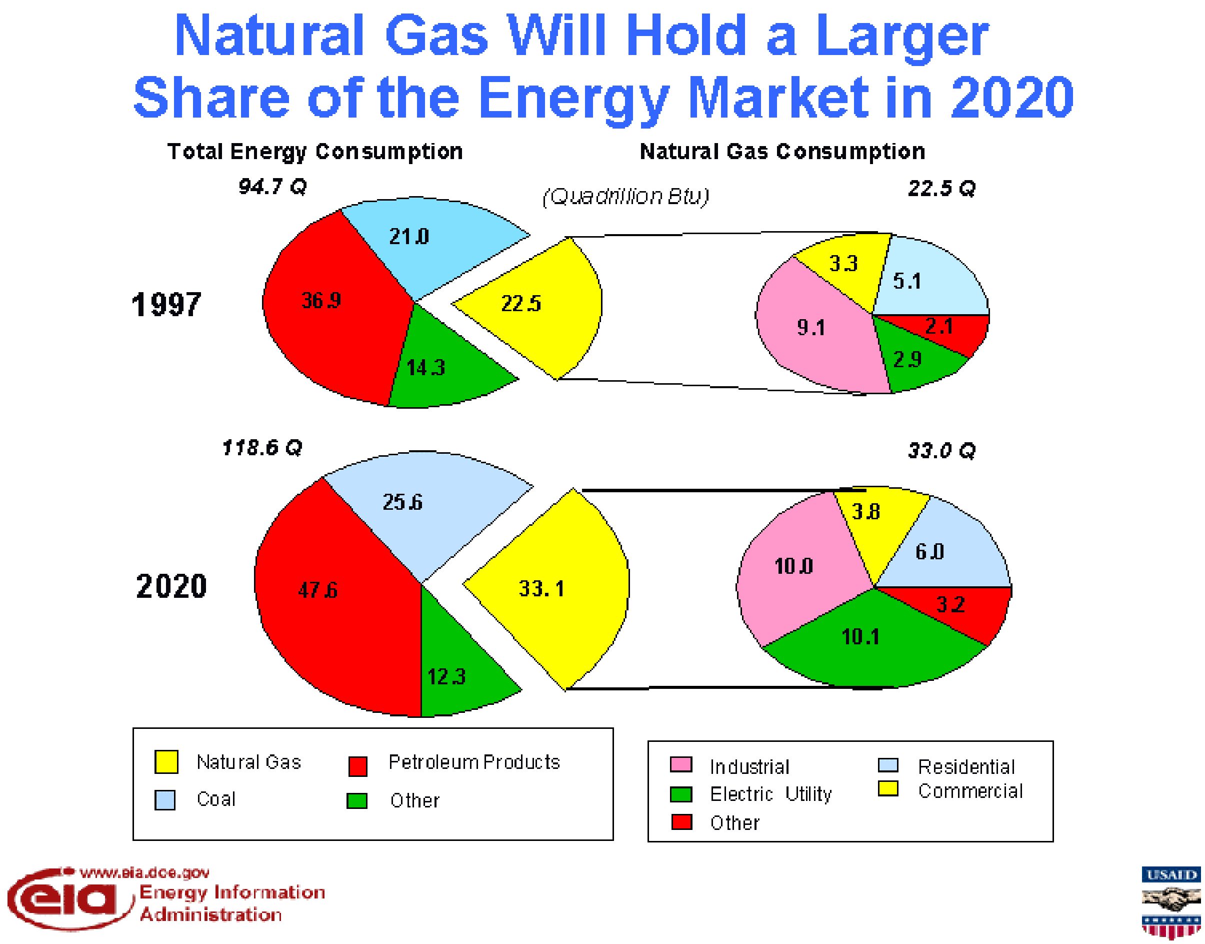


Figure 6: Natural Gas Storage Fields



Source: Barbara Mariner-Volpe, "The Evolution of Gas Markets in the United States" Energy Information Administration, Slide-show presentation, May 2000. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/presentations/2000/evolution_gas/index.htm>

Figure 7: Natural Gas's Share of Energy Market



Source: Barbara Mariner-Volpe, "The Evolution of Gas Markets in the United States"
Energy Information Administration, Slide-show presentation, May 2000.
<http://www.eia.doe.gov/pub/oil_gas/natural_gas/presentations/2000/evolution_gas/index.htm>

January 2001 contract at almost $10 per MMBtu -- over ***four times*** greater than the January 2000 and January 1999 last-trade date settlement prices for the NYMEX gas futures contract. A recent snapshot of settlement prices for actively traded NYMEX gas futures contracts reveals market expectations that wholesale Henry Hub gas will cost between $5.00 and $5.50 per MMBtu through next January. (Note: One MMBtu equals 10 therms). The graphs also show the close relationship between retail PGA rates and wholesale gas prices over the last two years.

What is the cause of the higher gas prices? In short, respondents to the NOI (as well as various experts that have addressed the issue before the Commission) agree that the price increases are the result of the law of supply and demand. Respondents identified the following factors which lowered supply and raised demand, apparently leading to the change in market prices observed over the period under review in this NOI:

Supply-side factors

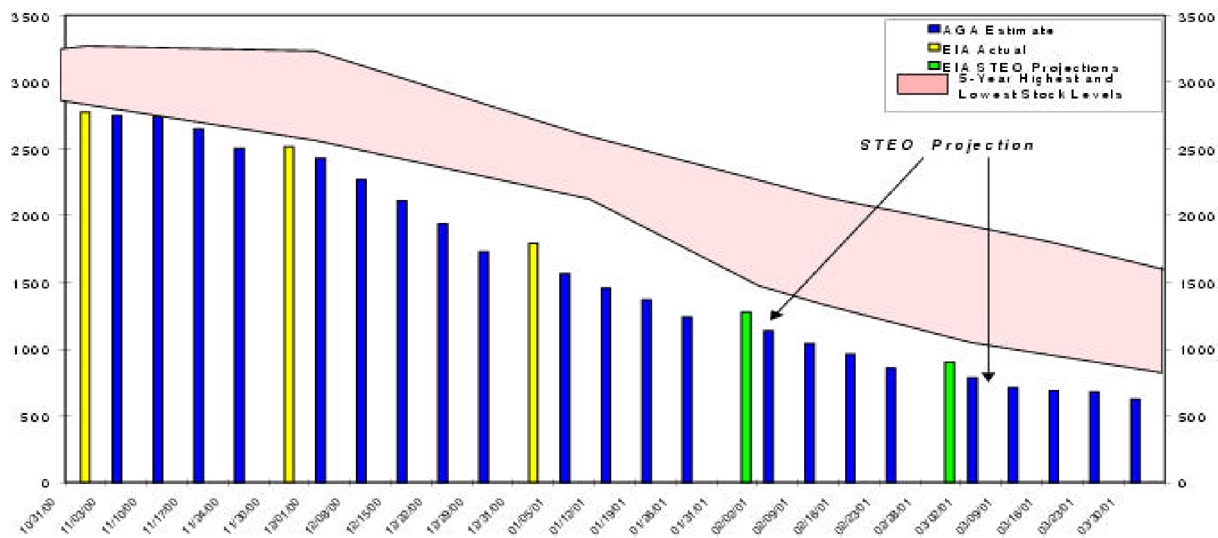
- Reduced investment. Persistently low prices in 1990s inhibited investment in exploration and well development. For example, rig counts dropped from 627 in the 4th quarter of 1997 to 396 in the 2nd quarter of 1999.
- Learning curve. Original expectations for production capability were not met due to the learning curve associated with new drilling technologies.
- Low storage. Prior to the heating season, high summer prices (and perhaps false expectations of subsequently lowering prices) reduced the extent of production-area storage injections. Storage inventories from the beginning to the end of the heating season (and a comparison of this season's levels to highs and lows over the previous five years) are show in Figure 8, below.[2] Also see the Energy Information Administration report, "Natural Gas Storage in the United States in 2001," by James Tobin and James Thompson.[3]

[2] Low storage levels were also noted in the testimony of Mark J. Mazur, Acting Administrator of the Energy Information Administration, before the U.S. Senate Committee on Energy and Natural Resources, December 12, 2000. He noted that inventory levels on December 1, 2000 were 14 percent below the average level for this time of the year during the previous 5 years (1995-1999). See <http://www.eia.doe.gov/pub/oil_gas/natural_gas/ presentations/2000/testimony_on_natural_gas_demand/1211sen-test.pdf>

[3] <http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2001/storage_outlook_2001/storage.pdf>

- Pipeline capacity. Respondents also cited recent additions to pipeline capacity both entering as well as leaving the State. Various respondents opined diversely that the net effect of these pipeline additions on prices in Illinois was negative, positive, neutral, and indeterminate.

Figure 8: Storage Inventories Actual and Projected



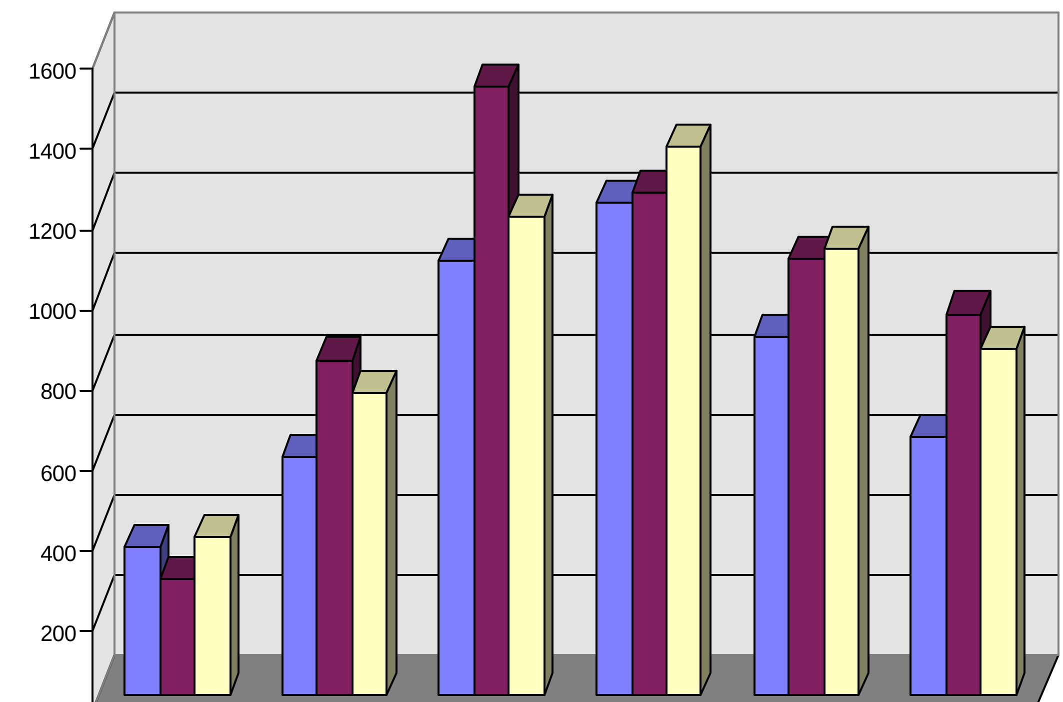
Source: Energy Information Administration's Weekly Storage Report, April 9, 2001
<http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_weekly_market_update/ngwmu.html>

Demand-side factors

- Macro-economic. The economic boom of the 1990s spurred production of many goods and services and the demand for natural gas used in their production.
- Increased number and utilization of natural gas-fired electric generation facilities. Increased natural gas demand due to such facilities was presumably most pronounced during the summer, helping to keep market gas prices high and lowering the amount of gas being injected into production-area storage wells. No respondent was able to estimate the specific effect of increased use of gas-fired generation on the price of natural gas.
- Oil prices. Increased price of crude oil and its refined products, which are substitutes for natural gas as a fuel used in industrial processes as well as electric generation. By definition, demand increases in response to the increases in the price of substitutes.

- Stiffer clean-air regulations. Since in many respects natural gas is a cleaner-burning fuel than most other fossil fuels (like coal or fuel oil), stiffer clean-air regulations lead to an increased use of natural gas by industrial customers seeking to comply in the least-cost manner. However, as one respondent pointed out, as long as such standards accurately reflect the environmental cost of the controlled pollutants, then the associated increase in the price of natural gas is appropriate and consistent with economic efficiency.
- Cold weather of November and December. Finally, the temperatures during November and December of 2000 were particularly low, driving up the demand for natural gas as a space-heating fuel. Figure 9 below shows the heating degree days over the last two heating seasons, as well as the historical average ("normal") number of heating degree days for

Figure 9: Chicago O'Hare Airport Heating Degree Days



	Oct	Nov	Dec	Jan	Feb	Mar
99-00	368	591	1081	1224	892	640
00-01	286	833	1512	1248	1085	948
Normal	391	750	1190	1364	1109	862

Source: National Weather Service - Chicago Forecast Office
<http://www.crh.noaa.gov/lot/climate/>

heating seasons.[4] One respondent reported that the November to December 2000 period was the coldest in the last 106 years. This factor was cited more often than not as the reason why the winter prices exceeded expectations that had been formed during the summer of 2000 and reported to the Commission at an August 8, 2000 Gas Policy Committee meeting. Finally, for residential consumers, both the shift in demand due to weather, as well as the fact that their demands tend to be "inelastic" in the short-run, led to a substantial increase in the **quantity** demanded at the same time that the prices were at such high levels. Hence, for these customers, total bills this winter were significantly greater than in previous winters.

- Inappropriate regulated rate design. A more controversial theory, expounded by one NOI respondent, was that regulation at both the federal level and the state level contributed to the demand peaks by allocating too much of pipeline and distributing costs on the basis of peak demand rather than annual demand. In the NOI manager's opinion, this theory is flawed. In any event, pipeline and distribution costs are a relatively small portion of the overall retail price of gas. Hence, even if valid, the theory could only explain a limited portion of the price increases observed.

To conclude the discussion of demand-side factors, Figure 10, below, shows both the recent history and the near-term projection of gas demand by various sectors.

Of the various supply and demand factors implicated above, none can be singled out as the culprit for the higher gas prices of the last 12 months. Many factors worked together to have the effect that is the subject of this investigation.[5] Furthermore, most if not all of the factors played out on a North American stage. They are neither attributable to nor experienced solely within any one state or region. The high gas price situation is not just an Illinois or Midwestern problem; it is a national phenomenon

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[4] Heating Degree Days ("HDD") are typically defined as the sum, over some number of days, of the maximum of zero and the difference between 65 degrees F. and the average temperature for the day.

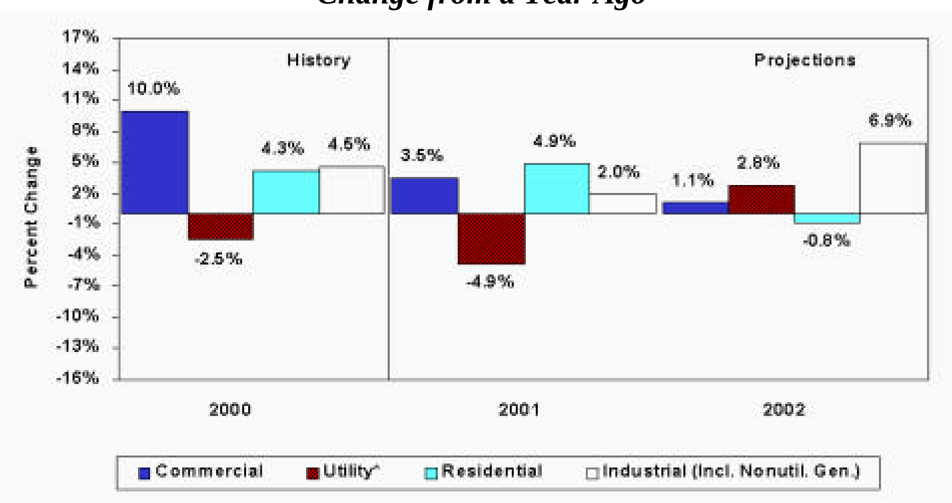
[5] Similar information was provided by Beth Campbell of the Energy Information Administration, before the Subcommittee On Energy And Air Quality of the Committee On Energy And Commerce of the U. S. HOUSE OF REPRESENTATIVES, at the subcommittee's Hearing On Natural Gas, February 28, 2001. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/presentations/2001/hearing_on_natural_gas/hearing_on_natural_gas.htm>

and a national concern. Independent of the NOI, Staff determined that significant PGA increases took place throughout the country.

In assessing the "adequacy" of supply for meeting recent gas demands, none of the utilities cited a "shortage" or an inability to meet their own customers' demands over the last several years. Most respondents were relatively sanguine about the future, as well. Some respondents noted that supply and demand responses are already being observed and will provide a market-based solution to the high price situation. As one respondent argued, the higher prices set in motion their own cure: conservation on the demand-side and exploration, drilling, and increased production on the supply side. As supply

Figure 10: Natural Gas Demand by Sector

Change from a Year Ago



Source: Energy Information Administration - Short-Term Energy Outlook, April 2001
<http://www.eia.doe.gov/emeu/steo/pub/contents.html>

increases and demand decreases, prices should fall. No party expressed concern of natural gas "blackouts" due to physical limitations on production, transmission, or distribution resources.

Finally, none of the participants attributed any of the price increases over the last 12 months to "market manipulation," as the Commission had phrased one of its NOI questions.

2. Conclusions and Recommendations

The NOI manager agrees with the conclusion reached by most if not all respondents: the high gas price situation was and continues to be a result of normal market forces in a competitive national marketplace for the commodity, natural gas. In addition, the NOI manager sees no reason for abandoning faith in the free-market economic policies that have served consumers so well over the years. This is not a blind faith, but one based on the economic history of market-based economies in general and the natural gas market in particular.

Wholesale natural gas prices were once subject to government regulation (price controls), which were lifted beginning in the late 1970s, when policy makers recognized that their price controls were not only unnecessary, but were actually harmful to consumers. They were unnecessary, since there appeared to be a large number of existing (as well as potential) natural gas producers, none of whom could exercise any significant market power over wholesalers or retail consumers. (See Table 3, below, for the current state of the industry). Hence, competition between suppliers could be expected to adequately protect the interests of consumers and keep prices from rising above the cost of production for any sustained period of time.

The price controls were actually harmful because they discouraged economically justifiable exploration and production, leading to a classic "shortage." In other words, at the price established, a greater quantity was being demanded by willing buyers than was being supplied by willing producers. Hence, a mechanism other than price was required to ration the limited supply among consumers. The government chose the highest uses of natural gas and limited the availability of gas to those chosen uses. Newly-built residential communities were often denied access to natural gas, due to this government-created and sustained shortage of natural gas.

All of this non-price rationing ended with the "deregulation" of wellhead prices. As was expected, there was an increase in gas prices. However, production increased and a natural balance between supply and demand was obtained through market forces. Soon thereafter, wellhead prices settled down to a level that fell between the previously regulated price of gas and the price that existed shortly after deregulation (See Figure 2: Natural Gas Wellhead Prices, p. 4). More importantly, the purchasers of natural gas rather than government agencies ultimately dictated what natural gas was worth to them, while producers competed to supply gas, as long as they were able to earn at least a normal economic profit. Such a market structure continues to this day, although, arguably, the market currently may be in a heightened state of disequilibrium, due to the various supply and demand shifts discussed earlier.

Table 3: Number of Producers, Pipelines, Marketers, Local Gas Utilities, and End Users

The U. S. Natural Gas Industry At A Glance

	Participants	Miles of Pipe	Regulatory Regime in 2000
Producers	8,000 Independents 24 Majors	0	Phased price deregulation Begun in 1979, completed in 1989
Pipelines	160	285,000	Federal Energy Regulatory Commission (FERC)
Natural Gas Marketers	260	0	Unregulated
Local Gas Utilities	1500	833,000	State Utility Commissions
End Users	Residential 53 million Commercial 4.5 million Industrial 40 thousand	0	Unregulated
	Electric Utilities 500	0	Interstate - FERC Intrastate - State Commissions

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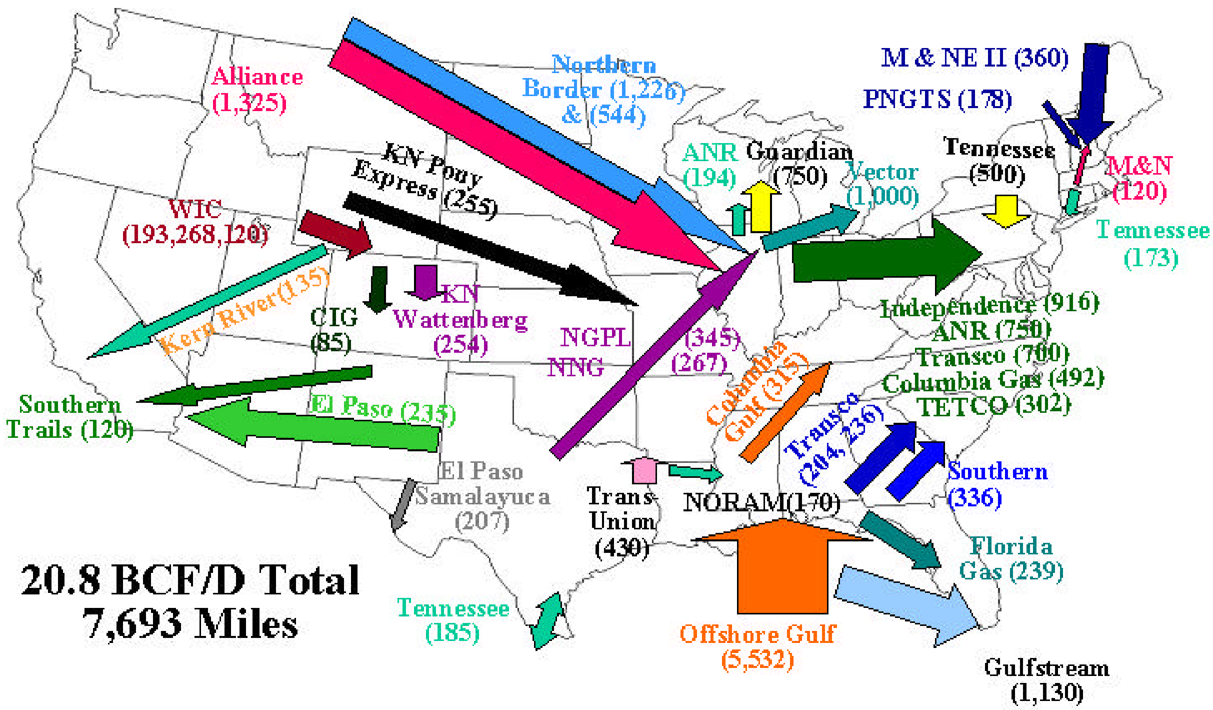
USAID

In the NOI Manager's opinion, no action should be taken by the State to disrupt the normal workings of the market for natural gas, where that market continues to be competitive. However, as has been recognized since before the deregulation of wellhead prices, the long-distance transportation and the local distribution of natural gas will most likely remain highly concentrated or monopoly industries. Thus, the services of interstate pipelines (regulated by the Federal Energy Regulatory Commission) as well as local distribution companies (such as the gas utilities regulated by the Illinois Commerce Commission) should continue to be price regulated.

As for interstate pipeline companies, since 1990, the level of pipeline capacity in the Midwest has increased by 16 percent, a percentage growth exceeded only by that into the Northeast.[6] Figure 11 below shows the major projects projects for 1997 - 2001 that have been certificated by the Federal Energy Regulatory Commission ("FERC").

Figure 11: Major Pipeline Projects Certified 1997-2001 (MMcfd)



(Source: FERC)

While natural gas consumption has grown steadily during the past decade, new pipeline construction has kept pace in the region. The growth in natural gas consumption in the Midwest has been met mostly through construction focused on expanding the deliverability of Canadian gas to the Midwest and Northeast. The bulk of that expansion is attributable to the Alliance Pipeline beginning service in December 2000. The Alliance Pipeline is capable of transporting up to 1,325 million cubic feet per day ("MMcfd") of natural gas from British Columbia to Illinois.[7] In addition to the Alliance pipeline, the new Vector Pipeline system became operational in December of 2000. Vector Pipeline is

[6] Department of Energy, Energy Information Administration, "Status of Natural Gas Pipeline System Capacity Entering the 2000-2001 Heating Season" (2000)
[7] http://www.alliancepipeline.com

a new 344-mile, 42-inch pipeline project that transports 720 MMcfd of natural gas from the Chicago area to parts of Indiana, Michigan and into Ontario, Canada.[8]

The completion of the Alliance project has the potential to result in short-term excess capacity in the Midwest. However, there is significant expansion focused on serving growing regional markets such as Wisconsin, Michigan and northern Indiana. For example:

- In February of 2000, FERC issued an Order allowing ANR pipeline to install two proposed 10,000 hp compressor units at the Woodstock, IL Compressor Station, which would provide a total of approximately 109 MMcfd into Wisconsin.[9]
- ANR is also pursuing a "Supply Link" expansion project that would allow a total of approximately 750 MMcfd to be transported from the Joliet hub to Indiana, Michigan, and Ohio. FERC issued a certificate for the Supply Link project in July of 2000.[10]
- CMS Energy, Viking Gas Transmission Company and WICOR are responsible for the Guardian project. Guardian will provide for the shipping of up to 750 MMcfd from the Joliet hub in to northern Wisconsin. The Guardian project received certification from FERC on March 14, 2001 and is not expected to commence operations until the fall of 2002.[11]
- Northern Border Pipeline Company's "Project 2000" consists of a 30-inch pipe, a new compressor station in Illinois, the upgrade of two existing Iowa compressor stations and a final delivery point in North Hayden, Illinois. Project 2000 will result in a system receipt capacity of 861 MMcfd in Chicago and 548 MMcfd to Northern Indiana. FERC issued a letter order in February 2001 authorizing construction of portions of Project 2000.[12]
- The Horizon Pipeline Company is a joint venture between Nicor and NGPL that would allow the transportation of 380 MMcfd from the supply hub at Joliet with the northern part of the Nicor Gas distribution system and an existing NGPL pipeline. FERC certification is pending an environmental review.[13]
- Trunkline Gas Company has filed with FERC a proposal to abandon and convert 720 miles of pipeline to transport refined petroleum products from Beauregard Parish, Louisiana to Douglas County, Illinois. Trunkline would continue natural gas service to existing customers by relocating certain gas taps to its two remaining parallel gas transmission mainlines. On March 9, 2001 FERC granted a certificate of abandonment and authorized the conversion with some restrictions. It is expected that the conversion will be completed in January 2002.

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[8] http://www.vector-pipeline.com
[9] FERC Docket CP99-241, 90 FERC ¶ 61,171 (2000)
[10] FERC Docket CP97-319, 92 FERC ¶ 61,022 (2000)
[11] FERC Docket CP00-36, 94 FERC ¶ 61,269 (2001)
[12] FERC Docket CP99-21
[13] FERC Docket CP00-129

The emphasis on proposals to redistribute the nearly 800 billion cubic feet of natural gas a year that could flow on the additional pipeline capacity now directed into the northern Illinois area by the Northern Border Pipeline system extension and the new Alliance Pipeline system (2000) could reflect the development of capacity constraint situations developing in the Midwest. This condition could be exacerbated if demand growth outpaces the implementation of these proposals. Nevertheless, there appears to be available capacity on routes in to the Midwest and these lines are not expected to be capacity constrained in any measure over the next several years.

As for the local gas distribution companies (the utilities regulated by the ICC), the Commission should consider how utilities could change and improve upon their natural gas purchasing practices (for example, greater utilization of price "hedges"), methods for estimating usage and bills in the absence of customer-specific meter read data, and efforts to inform customers of anticipated gas price movements. These issues will also be addressed in later sections of this report. In addition, each year, the PGAs are subject to annual reconciliation process, involving an audit and a prudence review of the utility's gas purchasing practices. Gas utilities are only permitted to recover prudently incurred gas costs. The Commission is currently reviewing last year's gas expenditures by utilities so that any imprudent expenditures can be detected and subject to refund as expeditiously as possible.

B. Efforts to Inform and Assist Customers

1. Discussion of Comments

This section of the investigation concerns efforts by the utilities 1) to explain and offer level/budget and deferred payment plans, 2) to promote customer understanding to manage gas consumption, 3) to describe what measures were and could be taken to alert customers of the potential for increased gas prices, and 4) to describe eligibility requirements for participation in a deferred payment plan.

The investigation of the high gas cost in the winter of 1996-1997 (97 NOI-1) led to a recommendation that utilities provide their customers timely and early warning information about impending higher gas prices, including information regarding deferred payment and budget payment plans. As the result of that Commission investigation, utilities now routinely alert their customers to potential increases in natural gas prices.

Hence, as the market price of gas began to rise and predictions for further increases became widespread throughout the gas industry[14], Illinois utilities began alerting customers of the potential for high bills in the upcoming heating season of 2000/01. Through bill messages and bill inserts, gas utilities notified customers (beginning as early as May/June) of the expected increase in gas prices, an explanation of prices, payment plans, and conservation tips. Most companies sent multiple notices and all gas utilities had provided information to their customers by September/October.

Since early September, the Commission's Consumer Services Division ("CSD") has monitored the efforts of utilities with respect to communications, billing, collection, payment plans (both budget billing and deferred payment arrangements). The CSD is currently reviewing budget billing practices of gas (and electric) utilities.

The Commission's Consumer Services Division published a brochure, ***Understanding Natural Gas Prices / Natural Gas Energy Savings Tips,*** which offers information about the cost of natural gas and suggestions for reducing gas consumption. The material is sent to consumers who contact CSD, has been provided to legislators, and is available from the Commission's web site.[15]

In addition, Commissioner Ruth Kretschmer, Chairman of the Illinois Commerce Commission's Gas Policy Committee, hosted the Illinois Natural Gas Roundtable 2000 in Chicago. Meetings on November 17, 2000 brought together consumer representatives and industry representatives having a general knowledge of the natural gas industry as a whole and in-depth expertise in specific areas. Consumer participants included residential consumer advocates, large commercial users, large industrial users, and state and local government consumer representatives. Industry participants included representatives of producers, interstate pipelines, local distribution companies, marketers, and entities

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[14] Specifically, in the spring and early summer of 2000, there were reports of increasing natural gas prices and predictions of soaring prices for the winter heating season. Gas prices were the subject of articles in virtually every newspaper in the state. National and local television stations reported on the subject. Coverage of the increases in gas prices and the effects continue to the present.

[15] The Commission's web site <www.icc.state.il.us> has other information on the subject of high gas costs as well as links to related sites on the internet.

involved in research and technology. Participants shared their opinions on current issues and made recommendations for future policies or actions that should be considered.

In December, Commissioner Kretschmer issued a report to Commissioners, legislators, and the public. In her report, Commissioner Kretschmer offered her conclusions:

- A recommendation was made by the Consumer Participants that the Commission should consider adopting a "best practice" approach to budget payment plans rather than having payment plans vary dramatically across the state. This sounds reasonable. I will recommend that the Commission direct our Consumer Affairs Division to investigate this recommendation.
- The Commission should consider a recommendation to the Illinois General Assembly whether or not natural gas marketers should be certificated.
- Participants in both roundtables agreed that a realistic national energy policy is needed. I agree.
- A number of people also said that another roundtable should take place again in six to twelve months to discuss the changes in the industry. I will consider holding another roundtable at a later date.

Commissioner Kretschmer's full report is also available on the Commission's web site.

As the winter progressed, utilities, regulators, and public officials recognized the need of consumers to better understand natural gas prices, and the importance of providing information that could help customers manage their bills. Customers were encouraged to consider budget payment plans, conservation, and deferred payment plans if they owed past due amounts. Nevertheless, warnings from utilities, government officials, and local and national media about impending increases in natural gas prices did not prepare consumers for the bills they received. Prices far outstripped those predicted in the summer and early fall and temperatures in December were much colder than in recent years.

As the magnitude of the problem became more apparent, utilities reviewed budget billing plans and some made changes to their practices. Customers shocked by bills looked for options. Some utilities made revisions to their budget plans to make enrollment easier – permitting customers to enroll directly by check-off on the bill, allowing customers to enter budget billing plans any time of the year, and promoting enrollment as a way to manage bills. For customers already participating in budget billing plans, adjustments were made to budget amounts to help customers avoid huge underpayment at the end of the budget period.

In January, Governor Ryan announced the creation of an Energy Cabinet to coordinate and handle key energy related issues. Regional meetings were held across the state to educate the public about the state services available to help families cope with high home energy costs this winter. The Departments of Commerce and Community Affairs, Aging, Human Services, Illinois Commerce Commission and the State Fire Marshal participated in public meetings held in Rockford, Waukegan, Chicago Ridge, Chicago, Carterville, and Decatur. Members of Commission staff from the Consumer Services and Energy Divisions participated in each of the public meetings.

The availability of financial assistance was a subject of the regional meetings, referenced above. Financial assistance is available to low income households in Illinois through the Low Income Home Energy Assistance Program ("LIHEAP") This year, the General Assembly raised the eligibility level for LIHEAP from 125% to 150% of the federal poverty guideline. In addition to the increase in the number of customers served, the benefits for natural gas customers increased by 35%. This year $175 million is expected to be available, this includes $65 million from the state and $110 in federal funds. Last year $110 million was available. The program is administered by the Illinois Department of Commerce and Community Affairs ("DCCA") through thirty-five agencies that operate in all Illinois counties. Utilities are also working with DCCA to implement arrearage reduction programs.

In special open meetings on January 18 and 24th, the Commission conducted hearings on natural gas prices. The Chairman asked utilities for a description of voluntary initiatives summarizing their communication and billing practices. Utilities participated in conference calls and followed with a letter to the Chairman summarizing the their efforts.

The utilities reported considerable communications efforts beginning as early as the spring of 2000 to alert customers to rising prices, describe and encourage customers to consider options for managing bills, and provide conservation tips to help customers control their usage. These messages were conveyed through the following media and others:

- bill messages, bill inserts and newsletters
- web sites
- press releases
- speakers bureaus

- community meetings
- information to public officials and legislators
- informational packets to local stores selling weatherization items.

Utilities also informed their customers about the availability of financial assistance programs offered by the Department of Commerce and Community Affairs and provided contact information. Some of the major utilities have programs that offer financial assistance that are funded through voluntary contributions from customers and matching contributions from the utility. Other utilities have or are developing programs such as Illinois Power Company's *A Hand Up* program. This program allows eligible customers to work at non-profit agencies in exchange for assistance on bills.

Utilities made other efforts to address the problems experienced by their customers. Some provided special training to their customer service representatives. Most utilities modified their policies regarding budget billing and deferred payment agreements allowing more favorable terms for customers. Two companies reviewed estimated bills and revised them resulting in credits to customers.

On February 2, 2001, Chairman Mathias attended an energy town meeting sponsored by State Senator Shaw at Thornridge High School in Dolton. Roughly 300-400 people attended the event. Questions pertaining to the issue of gas prices and their consequences for customers prompted the Chairman to request information from utilities regarding shutoff policies for residential and small business customers.

Chairman Mathias also led conference calls to discuss utilities' plans to deal with delinquent accounts as the weather becomes warmer. Utilities described how they prioritized disconnection primarily based upon the customer's payment history. During the discussions, the Chairman urged the utilities to continue to initiate contact with their delinquent customers to encourage those customers to make arrangements for payment of their delinquent accounts.

In a memo dated March 5, 2001 to the Energy Cabinet, Chairman Mathias included the following description of his discussions pertaining to disconnection of service.

> <u>Shut Offs of Delinquent Customers</u>
>
> During recent discussions with Illinois LDCs I have been told that substantially more residential and small business natural gas customers will be delinquent on April 1, 2001 than

were delinquent one year ago. One LDC will have more than twice as many delinquent accounts and another almost a three fold increase. Only one company - Illinois Power - projects fewer of its natural gas customers to be delinquent this year. In addition, LDC delinquent account receivables are estimated to double from one year ago, totaling more than $385 million. Receivables for one LDC have more than tripled from a year ago and have doubled for two others.

Senior officers of LDCs have stated that they do not want to lose customers or incur the costs of unnecessary shut offs. They have stated that they want customers to contact the LDCs to arrange payment plans which will allow customers to pay down their natural gas bills. In private conversations and now publicly I urge the utilities to continue to initiate contact with their delinquent customers to encourage those customers to make arrangements for payment of their delinquent accounts before the start of the next heating season. LDCs must reach out to their customers and let them know that the LDCs are willing to work with their customers to prevent shut offs.

The Mayor of the City of Braidwood and the Peotone Village President met with the Commission's executive director on March 2, 2001 to discuss the cost of natural gas that Nicor Gas passes on to its customers. A letter from 10 mayors of communities in Will and Kankakee counties, along with petitions bearing 7000 signatures, were presented to the ICC's Executive Director, Charles Fisher. The petitions and letters call for the Commission to investigate natural gas prices and have been included in the official record of the Commission's investigation. During the meeting, the concern was expressed that constituents may not be aware of the availability of energy assistance. These concerns were passed on to the Department of Commerce and Community Affairs which administers programs to assist Illinois citizens with energy grants to help with heating costs and home weatherization.

The Commission adopted Resolution 01-0261 on March 13, 2001, urging utilities to forewarn Illinois natural gas customer with delinquent accounts of potential shutoff of service, continue to assist customers by offering payment arrangements for past due amounts and level payment plans, and informing customers that of the utility's willingness to work with them to avoid disconnection.

All utilities report that they will follow Commission rules concerning discontinuance of service. Most have voluntarily implemented more lenient collection policies that consider customer needs created by the high cost of gas this heating season. These policies include more favorable terms for payment arrangements. Some utilities will express their willingness to work with customers by contacting them prior to sending disconnection notices. Typically, utilities begin disconnecting service to customers who are delinquent as soon as the weather permits and certainly at the beginning of April. This year, utilities have delayed issuing disconnection notices and have purportedly prioritized disconnection of service based upon the customers' payment histories. Utilities indicate that customers who have made no effort to pay any portion of their delinquent bills will be the first ones scheduled for disconnection. Currently, the Commission's Consumer Services Division is monitoring the disconnection practices of the utilities to insure compliance with Commission rules and adherence to the utilities' voluntarily-adopted policies intended to address the special circumstances arising from this last heating season.

2. Conclusions and Recommendations

The NOI Staff finds that the utilities made considerable efforts to alert customers to the rising costs of natural gas and to inform customers of conservation measures, the availability of deferred and budget billing plans and energy assistance. These efforts were frequent and presented through a variety of media. The high cost of gas and cold December weather resulted in bill amounts that were at least double or triple those of the previous year. Despite these efforts, customers were shocked by the level of their natural gas bills this heating season. The NOI Staff also finds that utilities have modified their collection and disconnection policies to be more lenient with customers and help them manage the unusually high bills arising from this last heating season.

The NOI Staff recommends that utilities continue to inform customers of anticipated gas price movements, conservation measures, and available budget and deferred payment plans. Furthermore, utilities should continue to review and evaluate their communications and collection policies to identify potential improvements and determine the most appropriate ways to implement such improvements.

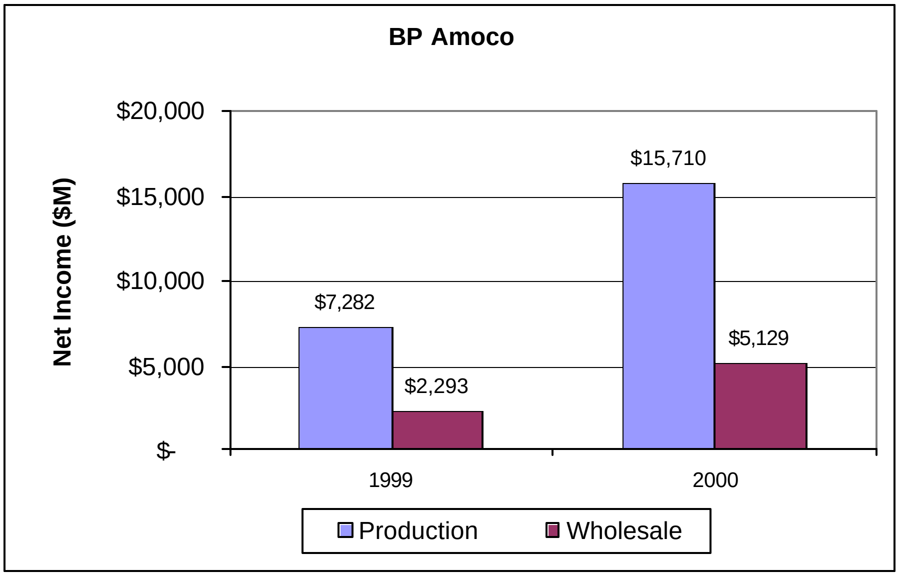
C. Supply and Production

1. Discussion of Comments

Respondents attribute the higher earnings that producers[16] achieved in 2000 to the high market price of natural gas and the decrease in supply from reduced exploration and drilling. The reasons producers set forth in their financial reports for increased revenue supported the explanations given by the Illinois utilities. Producers also attributed the increase in revenue to increased demand, acquisitions, and operational improvements. Texaco, in particular, attributed the high natural gas prices in the U.S. to concerns over low storage levels and strong weather driven demand.

Shown below are graphs of each company's earnings by their production and wholesale marketing segments. Note, however, that the companies do not report earnings on the same basis.

Figure 12: Production Company Earnings 1



[16] Producers reviewed were B.P. Amoco, Duke Energy, Enron, and Texaco. Enron combines wholesale and production for financial reporting purposes.

Figure 13: Production Company Earnings 2

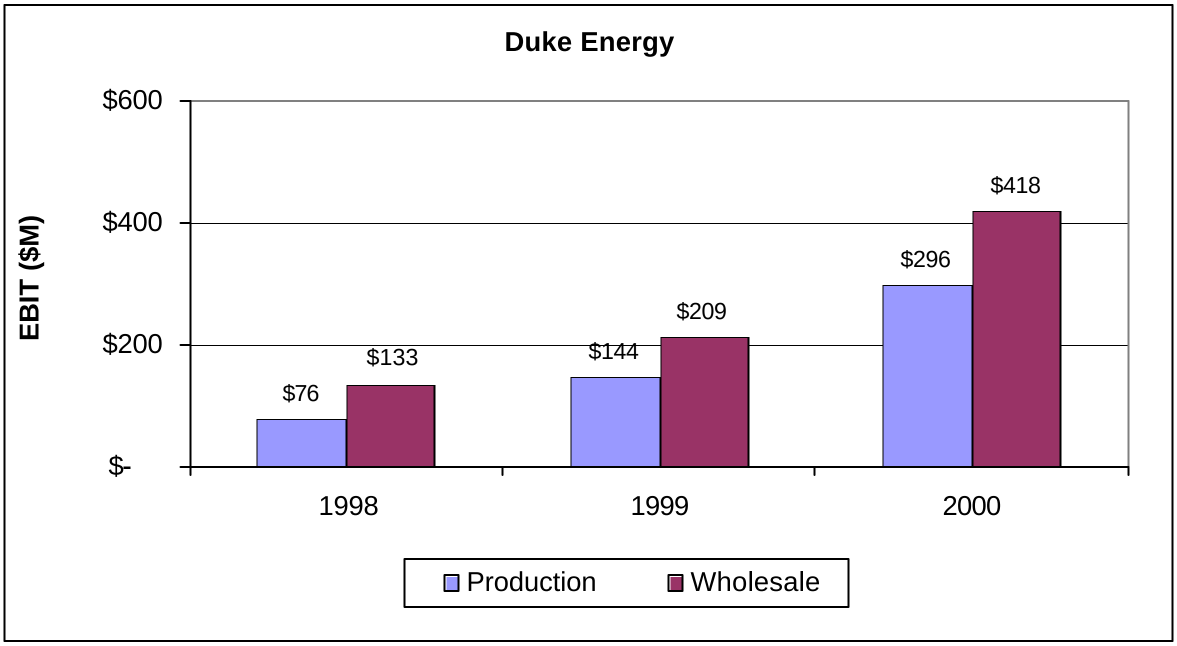


Figure 14: Production Company Earnings 3

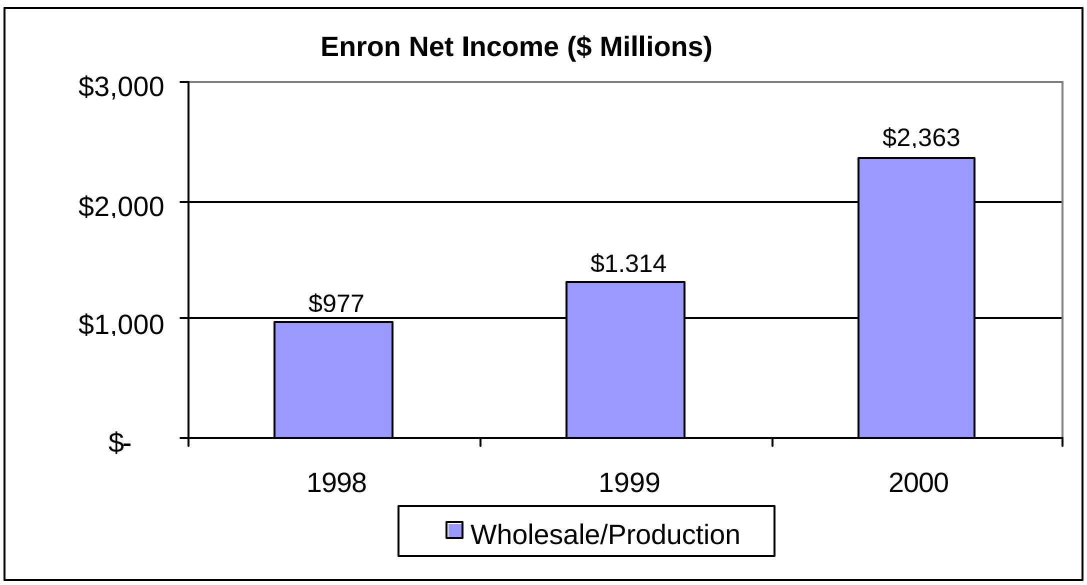
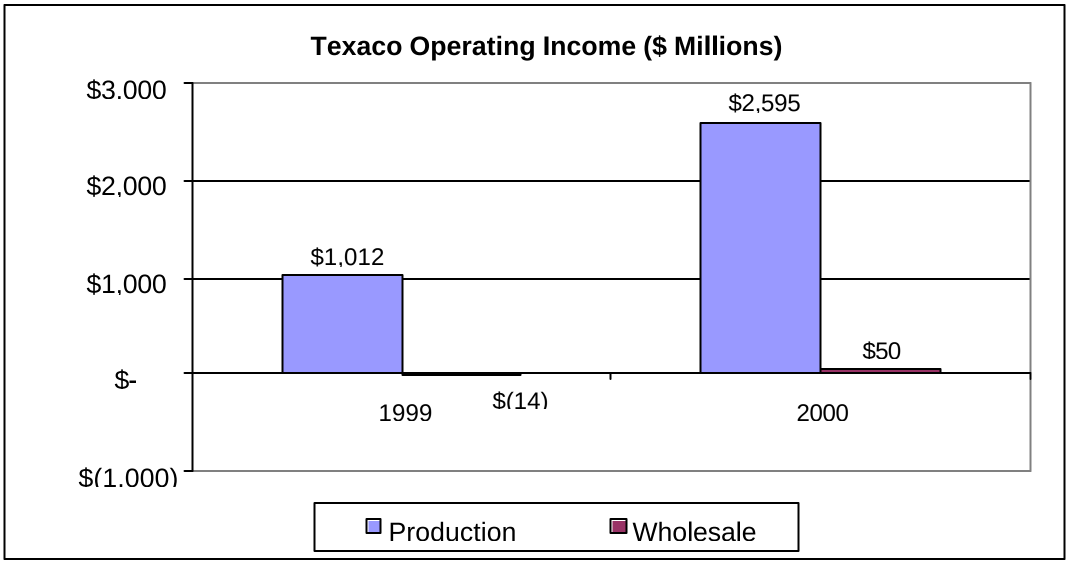


Figure 15: Production Company Earnings 4



2. Conclusions and Recommendations

There were no recommendations arising from responses to this section of the NOI and the NOI Manager has no recommendations, either.

D. Transmission

1. Discussion of Comments

Illinois utilities attributed increased revenues for transportation companies to an increase in throughput. They state that the higher volume was due to increased demand for natural gas, economic growth, new generation facilities, and severe weather. In their financial reports, transportation companies[17] offer the same explanation as Illinois utilities, but also added lower operating expenses as another reason.

The graphs below depict the net income and throughput of gas pipeline companies.

[17] Transportation companies reviewed were El Paso, Panhandle Eastern (CMS Energy), Texas Eastern Transmission - TETCO (Duke Energy), Texas Gas Transmission (Williams), and Northern Border (Enron).

Figure 16: Interstate Pipeline Company Earnings

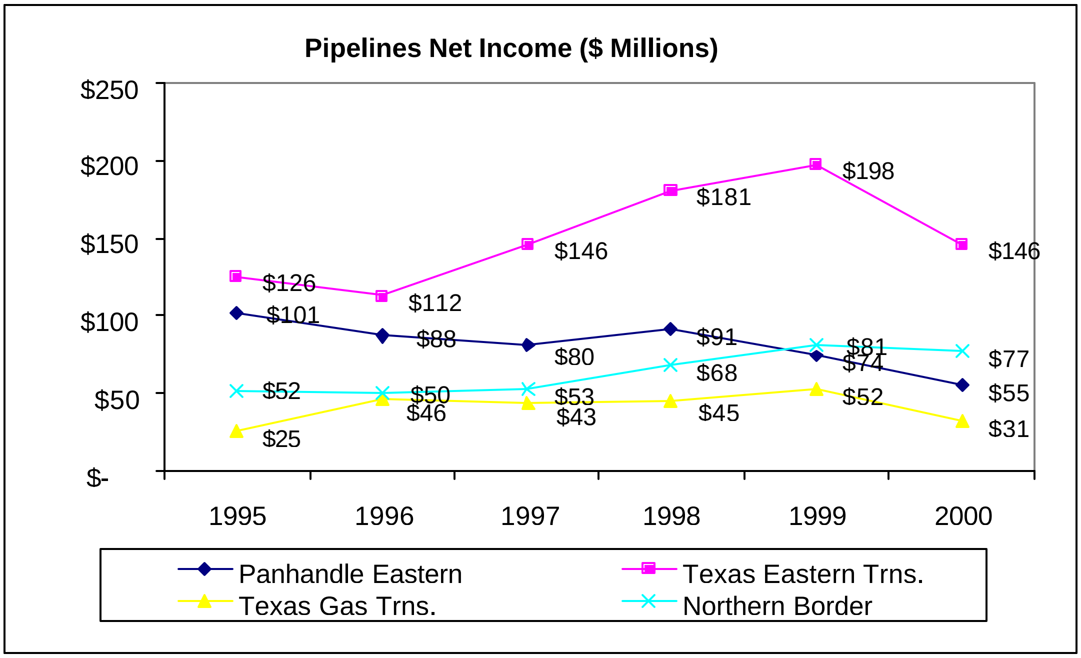
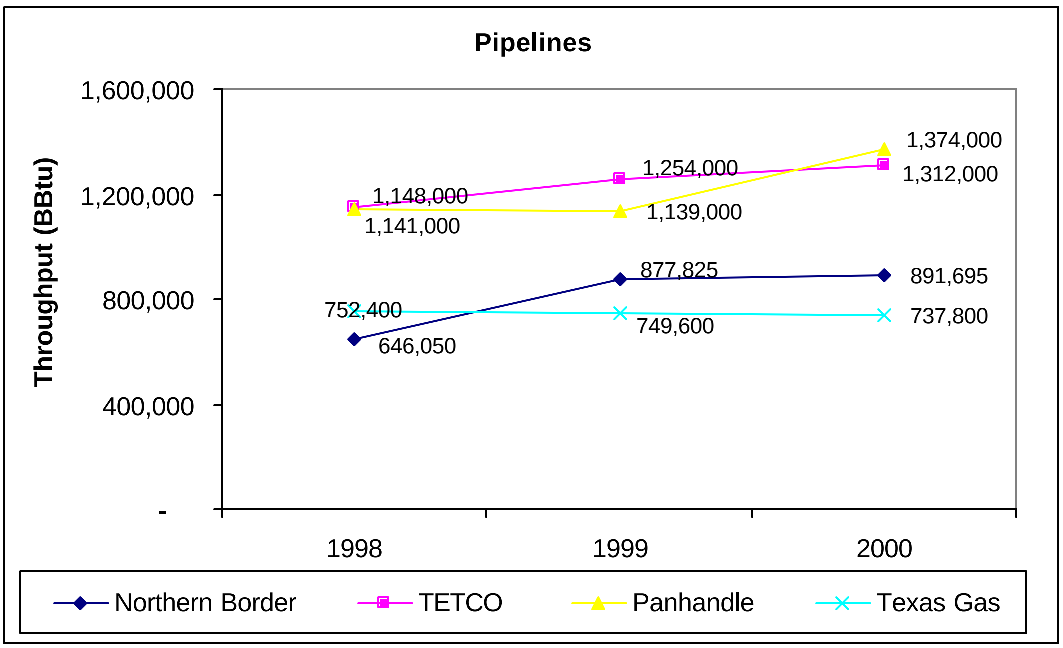


Figure 17: Interstate Pipeline Company Throughput



2. Conclusions and Recommendations

There were no recommendations arising from responses to this section of the NOI and the NOI Manager has no recommendations, either.

E. Distribution

1. Discussion of Comments

Question E.1 of the NOI solicited comments regarding the use of incentive rates by utilities in their Purchase Gas Adjustment clauses (PGA). Utilities expressing an opinion, for the most part, are in favor of the use of incentive rates with respect to recovering PGA costs but indicate that incentive rates must reach a proper balance between risk and reward. Utilities indicate that while incentive rates can result in greater savings and lower prices to customers, they cannot avoid volatility in gas prices because they are often associated with or compared to a market index or some other measure of market prices for gas. The Cook County State's Attorney's Office ("CCSAO") indicates that incentive rates are of dubious value and that competition among gas suppliers could provide the same benefits that are alleged to be provided by incentive rates. Such retail competition for gas supply of course requires the utility to offer a "customer choice" gas transportation program, which will be discussed later in this section.

Incentive rate mechanisms may be intended to mimic the risk and reward associated with the competitive supply of gas for profit. However, incentive rates may not be a good substitute for the competitive market place because of the difficulty in designing a reasonable proxy for the market prices associated with the variety of gas supply and transportation functions utilized to serve customers. Customers are more likely to realize the benefits of competition in gas supply if they can select their gas supplier from among many alternative suppliers.

In evaluating incentive rate plans, one must determine whether a utility's ability to perform better than a particular benchmark will result in the same efficiencies and cost savings observed in a competitive market with many suppliers. The latter is problematic because one must distinguish between results that would occur with and without the incentive plan. Nevertheless, NOI Staff views incentive plans, along with PGA elimination and customer choice transportation programs, as regulatory tools that, if designed properly, may improve customer welfare. Furthermore, the Act gives options to utilities to file incentive rate plans, as well as PGA elimination plans and customer choice plans.

Utilities claim that elimination of prudence reviews is necessary to encourage risk taking activity by utilities that will result in lower and more stable prices for customers. Staff reviews incentive rate plans filed by utilities to determine not only whether the plans warrant approval, but also whether the proposals are consistent with relaxation or suspension of prudence investigations. Indeed, Staff has accepted proposals by utilities to suspend prudence reviews, under the theory that the incentive mechanisms would be adequate substitutes for prudence reviews in impelling the utilities to minimize their gas costs. Indeed, Nicor Gas is currently operating under just such a framework.

In addition to problems inherent in the design and implementation of incentive rates, the NOI Staff agrees that incentive rates are not necessarily the best tool to use in limiting volatility in natural gas prices but they may be useful in mitigating the amount of wholesale price increases if they provide adequate incentives for utilities to negotiate lower cost wholesale gas supply and transportation contracts. Although incentive rates may result in lower cost gas by some amount less than a predetermined benchmark, it is likely that the benchmark and the incentive rates will fluctuate with general market supply and demand conditions and that contracts entered into under incentive plans cannot avoid the effect of market wide supply and demand conditions on price.

In any event, NOI Staff does not favor a Commission directive to utilities to begin implementation of incentive rate plans. Utilities are free to file incentive rate plans for Commission approval. Since utilities presumably benefit from retaining a specified share of savings from incentive rate plans there is sufficient incentive for utilities to file incentive plans without further Commission action. Since incentive rate plans are not a panacea for the increases in wholesale prices, there is no need for urgent Commission action to promote incentive rate plans.

Question E.2 solicited comments as to whether less frequent billing of PGA costs will contribute to gas price stability for retail customers. Utilities indicate that they oppose less frequent billing of PGA costs. Many utilities indicate that monthly billing of PGA costs is reflective of monthly pricing determinations in wholesale gas supply markets. Thus, if the billing of PGA costs to customers occurs less frequently, then customers are less likely to receive market price signals that can influence their consumption decisions. Illinois Power is the only utility that appears to acknowledge benefits from less frequent billing of PGA costs.

The CCSAO favors even ***more*** frequent billing (or at least more frequent communication of prices), in order to promote efficient consumption decisions by retail customers. In expressing this preference, the CCSAO opines that ***pricing*** stability should not be the objective; rather it is ***payment*** stability which should be pursued. Additionally, in its reply comments, the CCSAO proposed that the Commission examine extended budget plans (more than 12 months) as a means to help consumers during periods of high gas prices. The CCSAO gives an example to illustrate the payment implications of the proposed 18-month options versus the normal 12-month levelized payment options. This extended budget plan proposal is an issue in Docket 00-0789, regarding a Petition for Emergency Rulemaking and Expedited Investigation which the City of Chicago and the People of Cook County filed on December 12, 2000. Thus, this subject was expressly excluded from this NOI. However, documents pertaining to any open ICC docket are available from the Commission's eDocket web site: <http://eweb.icc.state.il.us/e-docket>.

The NOI Staff agrees with the position taken by utilities and the CCSAO that the monthly billing period for PGA costs should not be increased. Such an increase would likely obscure the market price signal to consumers and thus promote inefficient consumption decisions at times when prices are at their highest levels. Due to the way gas usage is measured and billed, there is little price discovery of PGA costs for the vast majority of retail customers prior to consuming gas, other than the filing of estimated monthly PGAs made by utilities with the Commission. The monthly PGA filings reflect previous over/under collections of gas supply and transportation costs and thus may distort current market prices depending upon the time period over which previous over/under collections are automatically reconciled (for some companies as long as 3 prior months.). If customers do not invest the time to discover the utility's estimated monthly PGA for the upcoming billing/consumption period (a relatively easy , yet obscure task), then the next opportunity for price discovery for customers occurs when they receive their monthly bills. The latter may not be problematic for the vast majority of customers when gas prices are in the $2-3 /mmbtu range, but when PGA prices double and triple and consume a larger share of a household's monthly income, it becomes more important for customers to decide whether they value consuming an additional unit of gas at given prices. Since lengthening the billing period to 3-4 months could remove pricing information from consumers' decisions to use gas over the majority of the heating season, customers would not receive the price signal that informs them of the value of consuming or conserving an additional unit of gas at times when the price signal is most crucial. The latter is likely to lead to higher monthly bills for customers than would be the case if customers had known prices in advance and at the end of each month to determine whether reductions in usage are warranted.

The NOI Staff is also in agreement with the CCSAO and utilities who indicate that the goal should be billing stability and not necessarily pricing stability. Customers have budget billing options that level the payments made over the course of the year and given the recent level of gas prices, customers should seriously consider enrollment in level payment plans because there is no indication that wholesale gas supply costs will decrease in the near future, i.e., for at least the 2001-2002 heating season.

Question E.3 solicits comments as to whether the PGA should be revised in any other manner. Utilities offer several suggestions, including: recovering capacity costs over the heating season rather than year-round, seeking a clear policy statement from the Commission regarding the recoverability of hedging costs through the PGA, promoting the use of hedging (via Commission statements), filing one PGA estimate with the ICC as close to the end of the month as possible, limiting the over/under collection from prior months to the immediate prior month in a PGA filing, and allowing the sharing of net revenues from off-system transactions. CUB requests that the Commission include the *failure* to mitigate for price volatility through the use of real and financial hedges in the Commission's prudence reviews for gas supply costs. The CCSAO indicates that the PGA can be deregulated with a well-designed customer direct purchase program.

The NOI Staff does not agree that capacity costs should be recovered only through the heating season. Although peak demand is achieved during the heating season, customers benefit from the use of transportation and storage services year round as a physical hedge against potentially higher heating season prices. Notwithstanding the previous statement, the use of natural gas to fuel electric generation to meet summer peak demands may reduce heating season/non-heating season price differentials in supply, storage, and transportation. Furthermore, if utilities desire to recover their capacity costs exclusively in the heating season months, no action is required of the Commission because such treatment is currently permissible under the 83 IL. Admin. Code, Section 525.10, Applicability, (a), that addresses the recovery of PGA costs. In Part 525.10(a), a utility is allowed to establish separate gas charges for recovery of costs of a seasonal nature, which could include capacity costs that are seasonal in nature.

The NOI Staff disagrees with those utilities that argue a need for the Commission to allow monthly PGA filings to be made as close to the end (or on) the last day of the month prior to their effective period. The PGA rule, in Section 525.10 (c), already provides this option to utilities. Section 525.10(c) requires that gas charge reports for the effective month must be postmarked by the 20th of the filing month, where the filing month is the month prior to the effective month. Furthermore, Section 525.10 (c) allows utilities to file another monthly report for gas charges up until the last day of the filing month. Monthly reports filed after such time require special permission from the Commission pursuant to Section 9-201(a) of the Act. Section 525.10(c) indicates that monthly reports filed after the 20th of the filing month will only be accepted to correct errors of a timely filed report for the same effective period. Currently Staff accepts revised forecasts or estimates of gas supply charges as sufficient reasons to accept revised filings.

The NOI Staff disagrees with utilities regarding the need for the Commission to allow Company's to shorten the time period over which the Adjustment Factor automatically recovers previous PGA over/under collections and other costs or credits because there is nothing in Part 525 that precludes utilities from limiting all Adjustment Factor costs/credit to those that were incurred in the month prior to the filing month. (Section 525.50)

The NOI Staff disagrees with utilities regarding the need to share off-system sales with shareholders because Staff is concerned that further encouraging such activity will result in the subsidization of the cost of holding capacity and encourage the accumulation of otherwise unneeded and excess capacity on behalf of utilities at the expense of ratepayers.

Even with the institution of customer choice gas transportation services, the NOI Staff would oppose the concurrent deregulation of the PGA because there is insufficient evidence that the market for retail gas supply service to residential and small commercial customers will be adequately competitive. The NOI Staff would prefer to see the continued regulation of the PGA until it is shown that competition at the small customer retail level will be robust enough to protect consumers' interests.

The various comments related to hedging are addressed in Section I, "Hedging and Risk Management," which begins on page 42.

Question E.5 asked utility respondents to discuss the extent of estimated meter readings and the methods used to calculate bills based on the estimated readings for the last four months of 2000 and 1999. They were also asked to identify the projected number of customers with current estimated meter readings who have potentially over/underpaid for their gas usage.

Although not all utilities who responded to the NOI reported an increase in estimates from the last four months in 1999 to the last four months in 2000, all who reported comparison numbers for October through December 2000 showed a substantial increase in estimates for December 2000. The only company to give a reason for the increase was Illinois Power, who cited weather related challenges and a bimonthly meter reading pilot program.

The utilities use various methodologies to estimate customer bills. All methods described in the NOI incorporate an individual usage factor based on some historical period, generally either the same period from the previous year or the prior month. Most also incorporate some type of factor based upon the weather for the billing period. Which methods produce the most accurate estimates have not been determined. However, at least one utility's methodology has been the subject of various consumer complaints due to seemingly incredulous estimates. In the NOI Staff's view, this utility's method is producing biased estimates of customer usage, and further review and possibly corrective action is warranted.

None of the companies identified the number of customers who have potentially over/underpaid for their gas usage, although Illinois Power reported that gas usage was overestimated by an average of 2.1%. At least two utilities, Illinois Power and MidAmerican Energy, rebilled customers with estimated readings in December. MidAmerican Energy used January reads and Illinois Power used actual weather data to reallocate gas usage between the December and January billing cycles. Bills were then recalculated using the gas charge in effect for each respective month.

If the components of the most accurate estimates were identified, a more uniform estimation process could be encouraged among the various utilities. In deciding upon changes to existing estimation procedures, the Commission should take into account both the costs and the benefits of achieving greater accuracy. For instance, the cost of implementing some changes may depend on the flexibility of the utility's customer information system. As far as benefits are concerned, it should be noted that the risk of substantial under/over charge to a customer due to an inaccurate use estimate depends on the degree of retail price differences from one month to the next. NOI Staff recommends that the Commission invite utilities and other potentially interested parties to participate in Staff-sponsored workshop discussions on the topic of energy usage estimation. Hopefully, such discussions will better facilitate the development of solutions to problems inherent in energy usage estimation.

2. Conclusions and Recommendations

Several utilities favor the use of incentive rate plans to recover PGA costs, but they do not necessarily view incentive rates as useful in mitigating wholesale price volatility. Two utilities indicate that properly designed incentive rate plans should include the elimination or circumvention of the Commission's prudence review process. NOI Staff recommends that the Commission refrain from issuing a directive or policy statement urging utilities to implement incentive rate plans. The Act already provides a mechanism whereby utilities may propose such plans. With each filing, the Commission is obligated to review the plan and determine if the proposal is in the public interest. Where called for in an incentive plan, the Staff and the Commission evaluate whether the prudence review process can and should be relaxed. The Commission is also authorized to condition approval of the plan on one or more modifications, but utilities are permitted under the Act to reject Commission-modified incentive plans. There is no barrier preventing utilities from filing and the Commission from approving appropriate incentive rate plans.

Comments are nearly unanimous in their opposition to extending the billing period for PGA costs, such that retail customers are billed less frequently. The NOI Staff agrees with utilities and the CCSAO that less frequent billing will distort price signals to customers at times when the information is most needed, and thus is likely to result in higher bills. The NOI Staff recommends that the Commission refrain from adopting less frequent billing for PGA costs.

Comments received indicate that the PGA rule could be altered to allow for seasonal capacity costs to be recovered in their entirety over the heating season months, the monthly PGA to be filed as close to the end of the month as possible, the shortening of the automatic adjustment factor period, the sharing of net-revenues from off-system transactions, and the elimination of the PGA to promote competition. NOI Staff does not support any of these recommendations as they appear either unneeded or unwarranted. Seasonal capacity charges, revised PGA up to the last day of the month, and foreshortened adjustment periods are all allowed under the current PGA rule. Allowing the sharing of net-revenues from off-system transactions would promote excess capacity holding by utilities at the expense of ratepayers. The current market for residential and commercial customers is not competitive and thus does not warrant the elimination of the PGA.

On the topic of gas usage and bill estimation, the NOI Staff notes a variety of methodologies currently in use. The accuracy of these methods is important when the retail rate varies significantly from one month to the next, as they did this last heating season. NOI Staff is not convinced that all of the utilities' methodologies produce adequately accurate estimates when actual meter reads are unavailable. To work toward solutions to problems inherent in estimating customer usage, and to better enable the Staff to make informed and appropriate recommendations to the Commission as to steps the Commission might take, NOI Staff recommends that the Commission invite utilities and other potentially interested parties to participate in Staff-sponsored workshop discussions on the topic of energy usage estimation.

F. Holding Companies and Affiliates

1. Discussion of Comments

Most of the respondents identified major operating affiliates. Two smaller utilities, Illinois Gas Company and Mt. Carmel Public Utility Company, do not have major operating affiliates. Some of the utilities do engage in transactions with affiliates regarding natural gas pricing and purchasing. The respondents generally maintain that they have in place adequate policies and practices to prevent inappropriate activities regarding these transactions. Generally, utilities that engage in gas pricing or purchasing transactions with affiliates maintain that they do so only when doing so is beneficial to their customers.

Pursuant to Section 7-101 of the Public Utilities Act, the Commission has some access to the records those affiliated interests that engage in transactions with a utility. Section 7-102 states in relevant part:

The Commission shall have jurisdiction over affiliated interests having transactions, other than ownership of stock and receipt of dividends thereon, with electric and gas public utilities under the jurisdiction of the Commission, to the extent of access to all accounts and records of such affiliated interests relating to such transactions, including access to accounts and records of joint and general expenses with the electric or gas public utility any portion of which is related to such transactions; and to the extent of authority to require such reports with respect to such transactions to be submitted by such affiliated interests, as the Commission may prescribe; provided, however, that prior to requesting such access or reports from the affiliated interest, the Commission shall first seek to obtain the information that would be included in such accounts, records or reports from the public utility. The Commission shall not have access to any accounts and records of, or require any reports from, an affiliated interest that are not related to a transaction, including without limitation a transfer or exchange of tangible or intangible assets, with the electric or gas public utility. Nothing in this paragraph shall limit the authority of the Commission otherwise provided under this Act to have access to accounts and records of, or to require reports from, the electric or gas public utility or to prescribe guidelines which the electric or gas public utility must follow in allocating costs to transactions with affiliated interests. (220 ILCS 5/7-101(2)(ii))

Section 7-101 further states:

No management, construction, engineering, supply, financial or similar contract and no contract or arrangement for the purchase, sale, lease or exchange of any property or for the furnishing of any service, property or thing, hereafter made with any affiliated interest, as hereinbefore defined, shall be effective unless it has first been filed with and consented to by the Commission or is exempted in accordance with the provisions of this Section or of Section 16-111 of this Act. The Commission may condition such approval in such manner as it may deem necessary to safeguard the public interest. If it be found by the Commission, after investigation and a hearing, that any such contract or arrangement is not in the public interest, the Commission may disapprove such contract or arrangement. Every contract or arrangement not consented to or excepted by the Commission as provided for in this Section is void.

The consent to, or exemption or waiver of consent to, any contract or arrangement under this Section or Section 16-111, does not constitute approval of payments thereunder for the purpose of computing expense of operation in any rate proceeding. However, the Commission shall not require a public utility to make purchases at prices exceeding the prices offered by an affiliated interest, and the Commission shall not be required to disapprove or disallow, solely on the ground that such payments yield the affiliated interest a return or rate of return in excess of that allowed the public utility, any portion of payments for purchases from an affiliated interest. (220 ILCS 5/7-101(3))

The Commission does have jurisdiction over transactions with affiliated interests, including gas pricing and purchasing arrangements. Furthermore, the Commission has initiated a proceeding, Docket No. 00-0586, whereby it will establish a rule addressing nondiscrimination in affiliate transactions for gas utilities.

2. Conclusions and Recommendations

There were no recommendations arising from responses to this section of the NOI and the NOI Manager has no recommendations, either.

G. Wholesale and Trading

1. Discussion of Comments

Respondents first were asked to assess the degree to which natural gas was diverted from the Illinois markets to the western states, such as California. Most respondents stated that they were unable to quantify the extent of such diversion or to assess its effect on gas prices. However, some respondents noted the existence of substantial price differentials between the western states and the rest of the country, during the period under review in the NOI. Specifically, prices for gas were higher in California than in the Midwest and New England states. While the higher prices were probably attracting supply that might otherwise have been sold in the Midwest, none of the Illinois utilities indicated that they were unable to meet the demands of consumers in their service territories. Some respondents also theorized that the price differentials were evidence of transportation constraints that were preventing even more diversion of supply. That is, in the absence of transportation constraints, the western prices would have been lower than they were and the Midwestern prices would have been higher, as the market sought an unconstrained equilibrium.[18]

The Commission also asked how the natural gas price spikes contributed to the robust fourth quarter 2000 earnings reported by gas trading companies and on how those earning affected the price of natural gas purchased by Illinois utilities. Responses to this question varied. Some verified the

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[18] At the Commission's January 24, 2001 Gas Price Roundtable Meeting, Cynthia Albert of CMS Panhandle Pipeline Companies estimated that 200 million cubic feet per day had been diverted from her company's pipelines and markets

assessment that trading companies' fourth quarter profits were generally robust, while others indicated that they had no knowledge of the situation. One respondent noted the obvious, that if a trading company buys low and sells high then they make profits. Another opined that trading companies profit more from price volatility than from high prices, particularly for trading companies that focus on managing risk for clients. Others acknowledged that there is probably a relationship between the high prices and high profits of trading companies. One company projected that the increased earnings might better enable gas trading companies to drill for new reserves. Another stated that if entry and exit are relatively easy and no trading company has dominant control over any essential facilities, then the issue of profits should not arise in policy discussions.

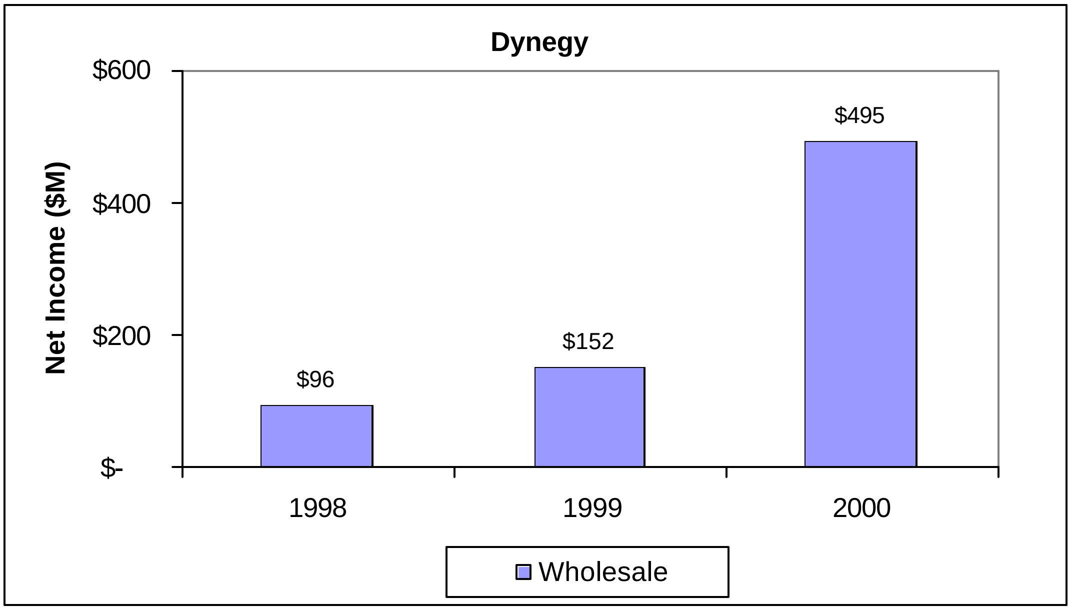
The financial reports of wholesale marketers[19] that NOI Staff reviewed coincided with the reasoning provided by the various respondents for wholesalers' higher earnings. Wholesalers also attributed the increase in revenue to improved operating efficiencies and the tight supply of natural gas coupled with an increase in demand for it attributed to the cold winter and the increased usage of gas-fired generation during the summer of 2000.

Below is a graph of Dynegy's wholesale sector's contribution to net income. The other wholesaler's income data was presented under the production section.

to serve California in recent months. Staff notes that 200 million cubic feet amounts to 0.2% of U.S. natural gas consumption per day over December 2000 and January 2001.

[19] Wholesalers reviewed were B.P. Amoco, Duke Energy, Dynegy, Enron, and Texaco

Figure 18: Wholesale Trading Company Earnings



2. Conclusions and Recommendations

There were no recommendations arising from responses to this section of the NOI and the NOI Manager has no recommendations, either.

H. Projected Natural Gas Prices

1. Discussion of Comments

Most respondents provided projections consistent with the March 30 NYMEX Henry Hub futures prices for open contracts, shown Section A, above (Figure 3, p. 5). For example, those futures prices peak for the January 2002 contract at around $5.50, with Chicago citygate wholesale prices about 20 cents per MMBtu higher. The Commission also asked about the likely effects on gas prices of low storage levels at the end of the withdrawal season and the introduction of new natural gas-fired electric generation plants in Illinois. While respondents were reluctant to speculate on the degree to which these variables will affect natural gas prices, comments reflect an expectation that prices throughout 2001 will remain relatively high.

2. Conclusions and Recommendations

The NOI Manager has no reason to doubt the predictions of respondents and the market that gas prices will remain in the range of around $5 to $5.50 per MMBtu. However, at the time of this writing, (on Monday, April 9, 2001, 11:22 ET), Henry Hub spot gas were trading higher, with the January 2002 contract at about $5.95. In the spot market (on Friday, April 6, 2001), Henry Hub gas traded at $5.33 and Chicago Citygate at $5.43 per MMBtu. The NOI Manager has no recommendations arising from this section of the NOI.

I. Hedging and Risk Management

1. Discussion of Comments

As one might see from the graphs shown in sub-section A, above, gas utilities' monthly PGAs over the last two years have been highly correlated with wholesale spot market prices. However, such a result is not inevitable. In particular, by entering into certain natural gas supply and/or derivative contracts, the month-to-month variations in prices paid by the utilities and/or retail consumers can be reduced or almost entirely eliminated. In general, such a strategy is commonly referred to as "hedging."

In recent years, utilities' winter gas needs have been met through a combination of storage withdrawals of gas which was injected during the summer and fall and additional purchases from the market. Many of those purchases were from the spot market or at prices that are linked by long-term contract to one or more spot market price indexes. Utilities may also enter long-term fixed price contracts or purchase futures or options in advance of the winter heating season, in order to reduce the PGA's overall exposure to spot price volatility. While some Illinois utilities have used such measures for relatively limited portions of their expected winter demand levels, generally speaking utilities have not been hedging to more substantial degrees.[20]

Most of the parties expressed the opinion that hedging activities can dampen price volatility but may entail additional costs. However, they also warned that hedging would not create cheap gas. For

[20] One apparent exception to this rule is Ameren. At the January 18, 2001 roundtable discussion, Scott Glaeser of Ameren noted that "Our strategy is that two-thirds of our winter supply will be hedged in some form or another, whether it be by storage or by fixed price gas or various financial instruments embedded in the current gas supply agreements." He latter described the use of "fixed-forward deals" and "cost-less collars."

example, locking in a price in advance of the winter heating season does not guarantee that such a price will continue to be the lowest available to the utility. That is, spot prices may subsequently fall and enable the utility to purchase gas for less than the longer-term forward or futures price available months or years earlier. The opposite is also true, as demonstrated throughout 2000.

Many respondents explained the utilities failure to engage in more substantial hedging activities on the lack of clearer signals from the Commission. Some respondents went so far as to claim that the Commission has actively discouraged hedging activities. From their comments, some utilities appear reluctant to adopt more aggressive hedging strategies for fear of unfair hindsight prudence reviews, particularly when spot market prices happen to fall below previously locked-in prices. To address this fear, some respondents recommended that the Commission adopt an appropriate administrative rule or articulate a more supportive hedging policy in some manner other than a rule. Finally, in its reply comments, CUB recommended that the Commission declare that a utility's failure to utilize a variety of hedging tools will be considered evidence of potentially imprudent conduct.

2. Conclusions and Recommendations

For many respondents, hedging is a significant issue. The following discussion explains Staff's position and reviews the Commission's record with respect to utility hedging activities. This discussion demonstrates that neither the Staff nor the Commission is opposed to hedging or liable to second guess legitimate risk management activities when hedged gas costs turn out to be higher than subsequent spot market prices.

First, NOI Staff agrees with most or all respondents who said that hedging does not guarantee lower costs either in the short-run or in the long-run.[21] Hedging reduces exposure to price variations over some time interval. For example, hedges created now and maintained through January 2002 will reduce the degree to which buyers are helped or harmed if January 2002 spot prices decrease or increase, respectively, relative to current expectations.

[21] During the Commission's January 24 Gas Price Roundtable Meeting, Donato Eassey of Merrill Lynch stated that "historically, for 13 of the past 15 years, you have been better off buying in the spot market because the spot market prices were lower than the firm prices." (Tr. 16)

Second, reducing retail consumers' exposure to such price fluctuations has advantages as well as disadvantages. One advantage is certainly easy to understand. Consumers do not like huge unexpected price increases for commodities as important to them as natural gas. The disadvantages can be a bit more difficult to fathom. For instance, one disadvantage is that reducing retail consumers' exposure to price fluctuations in the spot market reduces economic efficiency, which is one of the objectives articulated in the Public Utilities Act.[22]

For the above two reasons, Staff, to date, has neither advocated nor opposed efforts to reduce price risk through gas utility purchasing strategies or hedging programs. This neutral Staff position has been articulated in numerous instances over the last several years.

For example, in ICC Docket 94-0403, the Staff did not object to the PGA Rule permitting the inclusion of *"price management"* (an obvious synonym for hedging or risk management) in the definition of Recoverable Gas Costs.

In a PGA reconciliation case involving Peoples Gas Light and Coke Company, a Staff witness testified as follows on the subject of hedging:

> Q. Are you opposed to hedging?
>
> A. No. In fact, had the Company actually hedged more than it did, as advocated by Mr. Ross, I probably would ***not*** be saying that the Company was imprudent for hedging. The only reason that I add "probably" to that statement is that a prudence determination would have to look at several factors. For instance, the Staff would have to determine if the Company knew what it was doing and instituted a valid hedging program in a valid manner. My point is just that "hedging" is not automatically imprudent. (Docket 97-0024, Rebuttal Testimony of Richard J. Zuraski, July 20, 1998, p. 3)

In other PGA reconciliation cases, Staff noted the existence of valid hedging activity by utilities. Even in instances where these hedges ended up with ratepayers absorbing significant financial losses,

[22] As Mr. Eassey observed, "if … you try to freeze rates or insulate the consumer, you are in fact setting a false sense of reality, and not setting right price signals and I think you just dig yourself a new bigger hole, à la California." (Tr. 18-19) To explain further, if the spot price of natural gas, "S," along with the marginal cost of producing the commodity, decreases below a previously locked-in forward price, "F," consumers that must pay F will continue to consume the product only up to the point that the product is worth F. At that point, there will still be producers willing to produce more natural gas at a lower price. If, on the other hand, the spot price, "S," increases relative to the forward price, "F," then those consumers will consume natural gas beyond the level at which its value to consumers is equal to the cost to produce. In either scenario, resources are wasted due to the rate freeze.

Staff did not seek prudence disallowances. For example, after performing its prudence investigation of the annual costs incurred by Peoples Gas Light and Coke Company in ICC Docket 99-0483, the Staff concluded that the company's hedging activities were adequately planned and executed. Even though there were losses associated with those hedging activities, Staff recognized that the Company did reduce price risk for ratepayers through a reasonably well-conceived risk management plan. No Staff testimony was filed to this effect simply because none was needed. The Commission ordered no disallowances for Peoples in that case.[23]

On the other hand, while the Staff has encouraged the Commission to adopt a *laissez-faire* attitude toward the **degree** of hedging, that permissiveness does not and should not extend to the competence and conscientiousness with which hedging activity is designed and executed. The NOI Manager considers this to be a crucial distinction. The following examples may help explain this opinion.

Suppose hypothetically that a utility starts off by purchasing all of its gas at spot market prices or through contracts tied to spot market prices. Having enough storage capacity at its disposal for 30% of forecasted winter consumption, throughout the injection season, the utility, in essence, enters a series of hedges for that 30% of expected demand. Now, in addition, suppose that the utility decides to begin hedging a greater portion of its expected demand by entering into several forward contracts in May for the upcoming December, January, and February delivery months, in an amount approximately equal to 20% of the expected demand levels in each of those months. For instance, the utility agrees in May to buy a certain amount of gas in December for $5 per MMBtu. However, what if the Staff determines

[23] Staff also notes the comments of CUB's Executive Director, Marty Cohen, during the Commission's January 18, 2001 gas Price Roundtable Meeting:

> [I]t has not been Commission Policy to require hedging of any kind, but it has not been Commission policy to prohibit it. (Tr. 16-17)
>
> It's been left to utilities to make that decision. We think that they should be making those decisions in the interest of their customers. And if they are not taking prudent steps to minimize prices, they ought to be held accountable for that. (Ibid.)
>
> We have long held that some prudent hedging ought to be the case for any company. (Tr. 54)
>
> We would not object to a prudent strategy. (Ibid.)
>
> What that exactly would be would have to be subject to litigation, but it makes no sense at all for the utilities to claim we can't hedge; we are … prohibited from it; we have no incentive to do so. (Ibid.)

that on the same day in May that the utility agreed to buy December gas at $5, the average going rate for December gas forwards was more like $4? Having identified such a difference, the Staff might investigate further: Staff might examine the range of futures prices for December gas trading throughout that day in May. Staff might simply ask the utility why it spent $1 more than the average going rate trading in the forwards market. In other words, the Staff would attempt to determine whether spending $1 more than the average going rate was due, on the one hand, to a lack of prudence or an attempt to improperly funnel ratepayer money to an affiliate, ***or***, on the other hand, to extreme intra-day volatility in the forward market or a product entailing greater flexibility than the standard forward and futures contract.

Now, lets assume, for purposes of this hypothetical, that the utility had no good explanation for paying a dollar more than going rate for **forwards**. This should result in a disallowance. However, even if the December **spot** price ultimately fell well below that earlier going rate for forwards, it is my opinion that Staff would focus only on the $1 differential between the utility's cost and the contemporaneous going rate for gas forwards. Staff would not attempt to hold the utility accountable for what could only have been known through hindsight. Furthermore, if the spot price were to **rise,** instead, then the Commission should still issue a prudence disallowance for the $1 differential between the utility's cost and the contemporaneous going rate for gas forwards. That is, whether the hedge produced gains or losses in comparison to an unhedged gas supply portfolio, the utility should be subject to disallowance for an imprudent purchasing of a $4 product for $5.

Docket 97-0013 provides another example of where the Staff might question a utility's competence and conscientiousness in carrying out a risk management plan. In this PGA reconciliation case, the facts of the case showed that the utility had engaged in a series of transactions involving natural gas futures as well as options on futures. In the reconciliation year, the utility had sustained losses from the plan, which it had recovered from ratepayers through the PGA mechanism. The company mentioned that the losses were the result of hedging. After careful study of the utility's internal memoranda and transaction records, it eventually became clear that the utility's "hedging" consisted of

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In the last 16 years I have been following this very closely, a utility has never been disallowed a single nickel because they employed a strategy to try to minimize price volatility for their customers. They are scared of a phantom. (Ibid.)

two separate strategies, both involving natural gas derivatives. One of the strategies was an intra-seasonal strategy and other was an inter-seasonal strategy. The Staff witness argued persuasively and, indeed, proved mathematically, that the inter-seasonal strategy was not a valid hedging strategy, since it actually increased price risk to ratepayers:

> The main problem is that the inter-seasonal strategy does not constitute a valid hedge for ratepayers. If winter prices rise above expected levels, ratepayers are doubly cursed: (1) from paying the higher winter spot prices for non-storage gas, and (2) from absorbing financial losses associated with the inter-seasonal futures and options transactions. In contrast, if winter prices fall below expected levels in the winter, ratepayers are doubly blessed: (1) from paying the lower spot market prices for non-storage gas, and (2) from the financial gain associated with the inter-seasonal futures and options transactions. In short, the inter-seasonal strategy increases winter price risk. (ICC Docket 97-0013, Direct Testimony of Richard J. Zuraski, pp. 4-5).

Despite the above assessment, the Staff considered the utility's unwise strategy to have been an honest mistake. Later in his testimony, the Staff witness stated,

> … I am not recommending disallowance, for the following reasons.
>
> First, there may be value in allowing utilities to try something new every now and then, without the threat of overzealous prudence disallowance, even if some of their schemes fail to live up to expectations. Second, as far as I can determine, the Company's sole ***intent*** in this instance was to provide a benefit for ratepayers. Third, even though the strategy actually generated a loss in 1996, it was just as likely, *ex ante*, to have generated a profit. [footnote excluded] Fourth, had the Company's strategy generated a profit for 1996, it is unlikely that I would have recommended that the Company exclude those profits from the 1996 PGA and retain them for shareholders. In such an instance, my recommendation probably would have been for CILCO to discontinue its inter-seasonal strategy, for the reasons explained herein, but allow any already-realized profits to flow through the PGA for the benefit of ratepayers. Thus, disallowance in this instance does not seem warranted.

The Staff witness also found the intra-seasonal program to be of questionable value as a hedging program, but not nearly as objectionable as the inter-seasonal program, discussed in the above excerpt. The Commission ultimately found as follows:

> The Commission agrees that CILCO was not imprudent in investigating and utilizing the storage spread programs during 1996, and that CILCO properly recovered the net cost of the programs under the provisions of the Uniform PGA. **…** However, notwithstanding that CILCO was not imprudent in using the two programs in the past, the Commission believes

> the concerns voiced by the Staff are real, and that CILCO should not use the programs in the future. In the event CILCO or any other Illinois utility uses the intra-seasonal program or the inter-seasonal program in the future, the utilities shall be at risk of disallowance of the net costs incurred in connection with the programs. This conclusion is not a determination that Illinois utilities should or should not use hedging strategies or engage in futures market transactions. In the event that any utility uses hedging strategies or engages in futures market transactions, the Commission will consider such actions at the appropriate time as part of the review of any annual reconciliation in which the actions took place.

Thus, even on an occasion where the Staff discovered a utility unwittingly speculating rather than hedging on behalf on ratepayers, Staff recommended that the Commission grant considerable latitude, and the Commission acceded to that recommendation.

The NOI Manager agrees with many of the respondents who argue that the experience of at least the last year pushes in favor of ***more*** rather than less hedging. Utilities should never feel that they have *carte blanche* to do whatever they want, as long as they label it "hedging." However, they should not feel as if they are precluded from devising and implementing legitimate and prudent strategies that reduce price risk for ratepayers.

With respect to various respondents' call for some form of Commission direction or guidelines with respect to hedging, the NOI Manager does not recommend the promulgation of an administrative rule, which is the way in which the Commission issues statements of general applicability that implement policy. It is no more wise to create rules for hedging than it is to create rules for buying propane (used for adding peaking capacity), or the right mix of no-notice storage service versus must-nominate storage service, or the degree to which the company can rely upon firm transportation versus interruptible transportation services in swing months, or the best way to maximum revenue from release of temporarily-unused pipeline capacity, or any number of other details related to the prudent management of a utility's business. The Commission sets rates to prevent monopolies from taking advantage of market power; the Commission does not manage utility companies.

Furthermore, the legislature made a conscious decision, several years ago, to remove from the list of Commission responsibilities "Least-Cost Planning" for gas utilities (once described under section 8-402 of the Public Utilities Act). There is simply no need for the Commission to attempt to micro-manage the affairs of utility companies. Utilities should know how to run their businesses. But when they fail to meet expectations of prudence, whether in the realm of hedging or not, utilities should be held accountable.

J. Other Comments

1. Rate Design

On the subject of rate design for local distribution companies, the Cook County State's Attorney's Office recommended that:

> The Illinois Commerce Commission should initiate a Notice of Proposed Rulemaking concerning rate design for all natural gas distributors in which fixed costs are allocated among customers based 50% upon annual usage and 50% upon summer and winter peak use.

The CCSAO's suggestion is based on the assumption that residential and small commercial customers are subsidizing large customers through the rate design methodologies that the Commission has approved in the past. However, the CCSAO has not provided any support for this assumption, at least none that has not already been provided and rejected in previous cases before the Commission. Indeed, the CCSAO ignores the case history in Illinois of determining natural gas distribution charges.

Sometimes called, "base rates," these distribution charges are approved by the Commission, based on record evidence submitted by utilities, the Staff of the Commission, and intervenors which may include representatives of customer groups as well as governmental entities advocating on behalf of persons who take service within their respective boundaries (such as CCSAO). Base rates are for the cost to ***deliver*** natural gas; not for the cost of gas itself which is recovered through the monthly PGA rates. More specifically, base rates include the cost of production, transmission, distribution and other equipment, related labor expenses and operating and maintenance expenses. As noted in Section A, base rates did not increase over this last winter. Rather, the high retail price of natural gas this winter was due entirely to changes in the PGA rates.

During rate cases, the Staff of the ICC recommends natural gas delivery rates for each customer class based on established rate design principles, including the principle of assigning costs to the customers who cause the costs and the principle of assigning non-usage-sensitive costs to monthly customer charges and usage-sensitive costs to energy charges. The customer charge is a flat rate from month to month and is charged to the customer regardless of the customer's usage. Energy charges apply a price per therm to the customer's monthly therm usage. Thus, as the quantity of energy used (measured in therms) varies from one month to the next, the total energy charge varies, as well.

Assigning costs to the customer charge or to energy charges is a complex process utilizing many different allocation factors which are applied to the various cost accounts. The process has been established through the testimony of many expert witnesses in many rate cases. It is the opinion of the NOI Staff's rate design experts that simply applying a 50-50 assignment doctrine does not measure up to established principles of rate design.

To conclude:

- The CCSAO's suggestion to allocate fixed costs on a 50-50 basis does not have a strong foundation. The CCSAO has provided no compelling reasons to move away from more valid methodologies previously approved by the Commission, based on more solidly-formed evidentiary records.
- Conducting a Notice of Proposed Rulemaking (NOPR) on rate design is unnecessary, since the rates of natural gas distribution companies and the methods to compute those rates are normally determined through Commission rate cases.

2. FERC Intervention

In its initial comments, the Cook County State's Attorney's Office recommended the following:

> The Illinois Commerce Commission should petition the Federal Energy Regulatory Commission to commence their own Notice of Proposed Rulemaking to generically change the rate design employed by all interstate pipelines to the "Seaboard" format rather than the "Straight or Modified Fixed Variable." (CCSAO Initial Comments at 4)

The pipeline rate design practice of the FERC and its federal ratemaking predecessors has shifted over the last fifty-or-so years from Seaboard, to United, to Modified Straight Variable ("MFV"), to Straight Fixed Variable ("SFV"). The principle difference in these rate design methods is the relative amount of fixed costs that they recover via demand charges versus commodity charges. For instance, Seaboard recovers 50% of the fixed costs through the demand charge and SFV recovers 100% of the fixed costs through the demand charge.

The NOI Staff does not support generic FERC adoption of the Seaboard method for interstate pipeline rate design, while the Commission, historically, supported the use of MFV. In its comments in FERC Docket RM98-12, the ICC argued that shifting to MFV would provide benefits to Illinois. (Comments of the ICC, pp. 30-31). The MFV method recovers all fixed costs except return on equity and related taxes from the demand charge. (FERC Stats & Regs 30,939 at 30,432).

In February 2000, FERC issued Order 637. In Order 637, FERC did not adopt the ICC's recommendation to drop SFV in favor of MFV. Citing an industry in transition, FERC opted to postpone changes to several pipeline policies, including SFV rate design until after FERC Staff had examined the matter via a series of technical conferences under FERC docket PL00-1. (FERC Stats & Regs 31,091 at 31,267).

In spite of FERC's postponement of the rate design question, it is NOI Staff's opinion that Order 637 contains several features that afford pipeline customers the flexibility to mitigate negative effects that SFV may impose. Specifically, FERC revised its regulations to temporarily eliminate price caps for short-term released capacity and permit pipelines to file for peak/off-peak and term differentiated rate structures.

In addition to the flexibility afforded shippers by Order 637, FERC policy allows pipelines and shippers to negotiate rate agreements that include factors such as price, term of service, receipt and delivery points, and quantities to be delivered. FERC Stats & Regs 31,091 at 31,343. FERC adopted a negotiated rates policy in "Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines," (61 FR 4633 (Feb. 7, 1996), 74 FERC 61,076 (1996)).

Several Illinois utilities have indicated to Staff that they are capable of minimizing negative impacts that may be caused by SFV rate design (or any rate design). For example, the higher a utility's system load factor, the more it benefits from a pipeline rate design that collects a larger amount of the pipeline's fixed costs through the demand charge component of the rate instead of the commodity charge. Utilities with access to storage are able to use it to increase their load factor. The addition of gas-fired generation may also improve the seasonal use profile of pipelines. Also, several utilities indicated that they have been able to negotiate seasonal and volumetric pipeline contracts that more accurately reflect their demand as well as obtain discounts on maximum pipeline rates. In addition, marketers provide utilities and large demand customers with another option when negotiating with pipelines.

In addition to the mitigating factors, noted above, it is useful to keep in perspective the relatively small magnitude of the pipeline fixed costs at issue. The commodity cost of gas is, by far, the largest part of total gas costs.

> The representative throughput and projected discounts upon which rates are currently determined are out of sync with the changed and changing natural gas industry. Staff of the Illinois Commerce Commission should make this pleading in all interventions at the Federal Energy Regulatory Commission. Further, staff should issue a public report within six months outlining its initiatives and strategies. (CCSAO Initial Comments at 4).

The CCSAO's claim that "throughput and projected discounts upon which rates are currently determined are out of sync with the changed and changing natural gas industry," is more appropriately addressed in pipeline-specific rate cases at FERC, rather than in a generic rule-making proceeding. It is the NOI Staff's position that these matters involve material issues of fact, rather than policy questions.

The Staff of the ICC routinely recommends that the ICC intervene in cases at FERC that are expected to have significant impact on Illinois energy consumers. It would not be appropriate for the ICC Staff to intervene on its own behalf in FERC cases, as recommended by CCSAO. The CCSAO's recommendation raises the possibility that the Commission might also intervene on ***its*** own behalf and take a different position than that of its own Staff. Furthermore, it would be counter-productive for the ICC to make pleadings concerning pipeline rate design "in all interventions at the Federal Energy Regulatory Commission." Interventions at FERC are case-specific and must, of administrative necessity, be narrowly limited to the issues at hand.

Finally, NOI Staff points out that FERC rules permit CCSAO to file petitions or requests for declaratory orders at FERC. (18CFR 385.206 and 385.207, respectively). The CCSAO would also be able to file comments or intervene in FERC dockets. As an intervenor, the CCSAO would have the right to participate in hearings before FERC's administrative law judges, file briefs, file for rehearing of FERC decisions and have legal standing to be heard by the Court of Appeals if they press their opposition to FERC's final orders. In other words, CCSAO need not rely upon the Commission or the Staff to bring the CCSAO point of view before the FERC.

The CCSAO also recommends that

> The Illinois Commerce Commission should be testifying at FERC and the Congress to develop new rate structures that generate appropriate levels of profit and properly assign cost responsibilities. CCSAO Initial Comments at 14.

In response, NOI Staff notes that the ICC is active in any FERC proceeding that it feels could significantly affect the ratepayers of Illinois. The ICC was very active in FERC's pipeline restructuring proceedings leading up to the landmark open access rulemaking in FERC Order 636 in 1992. Since then, the ICC has continued to be actively engaged at FERC, submitting comments in numerous natural gas proceedings involving such matters as pipeline rate design, developing a secondary market for pipeline capacity, pipeline expansion, and facilitating mutual cooperation across the state/federal jurisdictional interface. It is less clear whether the Commission should attempt to broach the arcane subject of pipeline rate design with a law making body such as the Congress. It seems to NOI Staff that administrative agencies are much better equipped than legislatures to deal with the minutia within their own bailiwicks.

The CCSAO also recommends that

> This Commission should develop coalitions with other state commissions, with National Association of Utility Consumer Advocates, and the American Public Gas Association. (CCSAO Initial Comments at 14).

The NOI Staff agrees that coalition building with other State Commissions or public interest representatives can be beneficial to furthering public policy objectives. Most recently, with respect to gas cases before FERC, the ICC has actively participated in State Commission coalitions concerning Kansas *Ad Valorem* refunds on both the Northern Natural and Panhandle Eastern Pipelines. Other examples shall be omitted for the sake of brevity.

In summary, the ICC routinely participates in cases before FERC that have the potential to significantly affect Illinois ratepayers. The ICC participates in these cases on its own behalf or as part of coalitions. The "analysis" provided by CCSAO in both its Initial Comments and Appendix A does not convincingly show that new pipeline rate structures are desirable or that FERC's current approach improperly assigns cost responsibilities. Hence, the Commission should reject CCSAO's recommendation to petition FERC urging a reversion from SFV to the Seaboard method of rate design.

3. *Resale of Gas Supply and Capacity*

The CCSAO also made the following argument and recommendation:

> While Peoples Gas/North Shore state that in their service areas there has been switching by dual fuel customers away from natural gas, it appears to be less than optimal if the city gate natural gas price can reach the equivalent of $87 for a barrel of oil when crude oil is under $40 a barrel. It would be useful if the Illinois Commerce Commission staff conducted a survey of industrial and other gas users on whether they receive appropriate price signals to make such a shift. Further, when these customers have firm commitments for supply and capacity, can these customers easily resell their gas supply and capacity to others? Depending upon responses, the Commission staff may wish to promulgate a proposed change in this Commission's rules.

Staff objects to the suggestion that it should conduct a survey of industrial and other gas users on whether they receive "appropriate price signals," to induce economically efficient fuel switching.

This area of concern is clearly limited to relatively large users who have or can develop the ability to switch between natural gas and fuels such as No. 2 Distillate. All such users have the option to utilize unbundled gas service to purchase their natural gas not through the PGA but through third party unregulated gas suppliers through open access transportation tariffs. Indeed, virtually all such large customers have selected this type of service. Such customers are free to enter into contracts with suppliers that allow the price to fluctuate with a daily spot market price index, similar to the type of contracts commonly employed by utilities. With this type of contract, the issue of "appropriate price signals," is resolved.

On the other hand, suppose that these customer desire instead to enter into longer-term fixed price contracts. One might think that such a fixed price contract would dull and delay the appropriate price signal and sometimes lead to over-consumption of natural gas and under-consumption of fuel oil when the ratio of spot natural gas prices to spot fuel oil prices (per a common measure of energy content) rises somewhere above one-to-one. However, CCSAO's recommended remedy would deny the industrial customer the same relief from price volatility that so many respondents to this NOI appear interested in obtaining for other customers. NOI Staff does not see why the Commission should prevent gas customers from voluntarily entering into either fixed-rate contracts or fluctuating-rate contracts or to manage price risks in the manner most acceptable to them.

There are other reasons why more customers did not necessarily switch to fuel oil. According to the Energy Information Administration:

> Manufacturers' fuel oil storage capacity is declining rapidly. Another indication of the declining reliance on fuel oil by manufactures is the on-site storage capacity of the fuel oils. One of the problems of fuel oil relative to other fuels is that manufacturers must maintain large storage tanks. This can prove to be an added expense beyond the price of the fuel. Manufacturers must also guard against the environmental hazards brought about by faulty underground storage tanks.[24]

Whether it is increasing costs of maintaining storage tanks that comply with environmental regulations or some other fixed or variable costs that deter large firms from switching from natural gas to other fuels, NOI Staff has no reason to believe that these firms are not merely making informed economic decisions. The NOI Staff sees no reason to assume that there is a market failure or a regulatory failure at the core of the phenomenon cited by the CCSAO.

4. Impact on Consumers

The Midwest Community Council ("MCC"), located in Chicago, Illinois, focused its comments on the impact of the high gas prices this last winter on consumers. Through various examples, the MCC impressed upon the Commission that natural gas can be considered a "commodity of life." In addition, according to the MCC,

> [T]here are literally thousands of families and particularly small businesses, trying to determine if an avalanche of <u>incorrect estimated bills are correct</u>, doing it against a backdrop of **impending threats of being shut off**, and trying to figure out <u>how to make their dollars meet this unprecedented, and unfair challenge</u>. **…** Certainly any more energy assistance that can be found is greatly needed and appreciated, but everything does not have to equate to a trip to state coffers. In this case <u>it may simply require firm regulatory resolve as the law prescribes, to define 300% billings to customers as "unreasonable</u>". Let Peoples Energy live with the prices <u>they</u> paid for wholesale gas, and let everyday people <u>who had no choice</u> live their lives, raise their children. Let seniors mature into their years without a capricious assault on the precious funds they have, let Churches work for their members instead of Peoples Gas,

[24] (URL: http://www.eia.doe.gov/emeu/consumptionbriefs/mecs/mecs_fueloil_use.html)

> and let this be a lesson to Peoples Energy, to protect your customers. **…** In our opinion Peoples Energy is taking advantage of residents, churches, buildings owners, etc., believing that they can bill customers for their purchasing mistakes, and threaten collection by way of "shut off", to withhold these commodities of life, if captive customers without choice do not cooperate with this failure to protect.

Addressing these points, NOI Staff begins with the MCC's assertion of "incorrect estimated bills." As noted in previous sections, Staff will be following through with plans to re-examine utility methodologies for estimating bills with the intention of increasing their accuracy. By "impending threats of being shut off," NOI Staff notes that utilities are required by law to inform customers when their utility service is going to be discontinued. The NOI failed to show instances where a utility made improper threats. Finally, by "purchasing mistakes," NOI Staff believes that the MCC is referring to the failure to create a hedge for a greater portion of the gas portfolio. In this regard, NOI Staff does not agree that the reluctance to hedge was a product of imprudence. However, as explained more thoroughly in section I (starting on page 42), NOI Staff would certainly agree that utilities should give hedging a fresh look.

Given the MCC's grassroots attachments to the communities that it serves, NOI Staff accepts the organization's descriptions of how the lives of the citizenry have been affected by the price increases of the last twelve months for this "commodity of life" otherwise known as natural gas. These descriptions underscore the need for all stakeholders and regulators to continue to search for ways to mitigate the impacts of wholesale gas price increases on consumers.

X. Appendix A: Summary of Each Respondent's Answer to each NOI and Supplemental NOI Question